Petroleum news

page 10 Parnell: No tax hike, recommends some ACES tax credit changes

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FINANCE & ECONOMY

Cutting the cost of pipe

BP Alaska puts together direct imports of Japanese tubing to Port of Anchorage

By WESLEY LOY
For Petroleum News

It was 5 o'clock on a Saturday morning, Aug. 8, down at the Port of Anchorage.

Steve Sautel, logistics coordinator for BP Alaska, was there to greet a cargo ship that had sailed across the North Pacific Ocean, bringing a vital commodity and a new style of doing business to the state.

"It was a great feeling," he said, "to see the hatch open up and see pipe coming out."

Yes, pipe. A lot of it.

So far, three ships have made unusual stops to the Port of Anchorage to deliver a total of 17.6 million pounds of well tubing and casing, what folks in

see PIPE COSTS page 20

BP EXPLORATION (ALASKA) INC.

Crews offload tubular steel drill pipe and well casing from the bulk carrier Eternal Confidence last summer at the Port of Anchorage. The imported pipe is for use in BP's operations on the North Slope.

EXPLORATION & PRODUCTION

Farm-in at North Tarn

Brooks Range Petroleum to operate exploration program on Eni US lease

By KRISTEN NELSON
Petroleum News

Brooks Range Petroleum Corp. has added another exploration prospect to its North Slope agenda.

BRPC, the operating company for Alaska Venture Capital Group, has applied for operations approval for an exploration program at North Tarn, west of the Kuparuk River unit, on a lease owned by Eni US Operating Co.

The farm-in, which requires drilling the North Tarn No. 1 well, will earn a 24 percent interest in the lease for AVCG, 20 percent for TG World, 20 percent for Ramshorn and 16 percent for Bow Valley, BRPC told Alaska's Division of Oil and Gas. Those interests total 80 percent so Eni will retain a 20 percent interest in the lease.

Jim Winegarner, BRPC's vice president of land and external affairs, told Petroleum News in a Jan. 21 e-mail that the North Tarn No. 1 is the third well on the drilling schedule this winter, and would be drilled with Nabors Rig 16E after the Beechey Point unit Sak River No. 1A and the North Shore No. 3 wells are drilled.

"Given the short winter exploration drilling season, drilling a third well this winter will be challenging. If we do not drill the North Tarn No. 1 well this season, we will plan to drill it in 2011," Winegarner said.

Armstrong Alaska paid $181.17 per acre, a total

see FARM-IN page 19

GOVERNMENT

Vowing a fresh start

Alberta's new energy boss ready to rebuild partnership with petroleum industry

By GARY PARK
For Petroleum News

With blinding speed, he did what others before him had failed to accomplish and negotiated a pension plan with Alberta's teachers, then reformed the province's health care system.

RON LIEPERT

That's what Ron Liepert brings to the table along with a tough-guy reputation as he takes on the energy minister's job in Alberta.

In what might have been the understatement of the day, Premier Ed Stelmach described Liepert as "task-focused" as he introduced a new cabinet that could be his last chance to arrest a free-fall in Conservative party fortunes after 39 years of governing — often by landslide margins — in Alberta.

Stelmach said he wants Liepert to spend time at the industry's favorite hangouts in Calgary and open the lines of communication with an industry that has felt shunned by the government it has enriched and kept in power over the decades.

The reality for both men is that they don't have much time to mend a fractious relationship that has cost Alberta billions of dollars in upstream investment and thousands of jobs since Stelmach set about overhauling a royalty regime

see LIEPERT page 18

You'll receive Greening of Oil

Petroleum News subscribers will automatically receive Greening of Oil online magazine's weekly email, listing all GoO's stories for the previous week. The first email will go out Friday, Jan. 29.

'Have you sold out to the greenies?'

In the week following the first press release about the launch of Greening of Oil, sister publication to Anchorage-based Petroleum News, Kay Cashman has received almost 400 reactions to the online magazine, including, "It's an oxymoron; oil can't be green!" and "Have you sold out to the greenies?"

Greening of Oil's slogan, "Tracking energy's environmental footprint," might explain the latter comment, Cashman said, since the magazine's primary mission is to "track" the impact of oil and natural gas.

Readers of Petroleum News had a different reaction, said Cashman, publisher and executive editor of both publications.

"They were familiar with our reporting style, which is impartial, objective. They said everything from 'great job' and 'impressive Web site' to 'good to see journalists who

see GREENING OF OIL page 18

Juggling the gas mix; Apache targets LNG exports from Kitimat

Apache has now become the lead player in a venture that will test the outer limits of Canadian natural gas sales and determine whether there is a viable market in Asia.

In reaching a deal with Kitimat LNG to take 51 percent ownership of the proposed terminal on the northern British Columbia coast and 51 percent of the facility's planned capacity of 700 million cubic feet per day, Apache has taken a headlong plunge into what is designed as Canada's first LNG export project.

There's little sign of hesitation on Apache's part as the U.S. independent pushes ahead with plans to expand its Canadian activity in the British Columbia shale plays.

"Apache's investment in Kitimat LNG demonstrates our long-term commitment to the resource development in Canada and in particular in British Columbia," Apache's Canadian President Tim Wall told reporters in a conference call.

"B.C. represents an area of significant growth opportunity

see APACHE page 19

contents

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● ALTERNATIVE ENERGY

Get with it or lose out

Chris Rose: There are many business opportunities with renewable energies in the state

By ALAN BAILEY
Petroleum News

Renewable energy isn't a silver bullet that can somehow immediately replace all use of traditional fuels, but renewable technologies such as wind, solar energy and hydropower must form part of any energy portfolio, Chris Rose, executive director of Renewable Energy Alaska Project, told the Alaska Chamber of Commerce Make it Monday Forum on Jan. 11. The Renewable Energy Alaska Project is a coalition of Alaska utilities and other entities with an interest in developing renewable energy resources.

Renewable energy presents some significant economic advantages over more traditional energy sources, Rose said.

"When you don't have fuel costs, you can predict the price of the power," he said. "And that's what states and entities and corporations around the world are figuring out. … Stably priced, predictably priced power is one of the key advantages of renewable energy."

In addition, renewables tend to be clean and lacking in carbon emissions; they can often be produced close to where they are needed; and they form inexhaustible energy sources, Rose said.

Risk management

Risk management is a key issue in energy supplies, and a major risk at present in the United States is a heavy dependence on fossil fuels. Southcentral Alaska, in particular, is highly dependent on natural gas, Rose said.

There is an escalating international demand for energy, especially from countries such as China and India. Five Middle East countries hold 65 percent of the world's remaining oil reserves. And, ultimately, the finite nature of fossil fuel supplies will drive up fuel prices, leading to the inevitable emergence of renewable forms of energy as primary energy sources, Rose said.

Consequently, investment in renewable energy is growing at the rate of billions of dollars per year, especially in the fields of wind power and solar energy. And Alaska is already missing out on a huge emerging international business opportunity, Rose said.

"There are countries right now, like Denmark, that are getting 20 percent of all electricity from wind alone," Rose said. Iowa is now generating 15 percent of its electricity from wind, he said.

Progress in Alaska

Alaska has made progress in the direction of increasing its renewable energy usage, with a state renewable energy grant fund, primarily for developments in rural Alaska, providing $125 million in funding for 107 projects over the past 20 months, with another $25 million proposed for the state's 2010 budget, Rose said.

Under this program, and with some federal funding, Kodiak now has three massive 1.5-megawatt wind turbines that are saving about 1 million gallons of diesel fuel annually, Rose said.

"And at current prices … that's $2 million a year (in savings) for a project that cost $21 million," he said.

The Kodiak operation has involved the development of a control system that makes the most efficient use of wind-generated power in conjunction with diesel power and hydropower, thus making Alaska a world leader in the use of this type of integrated wind system, a system that could perhaps be exported to other countries.

> *"As a society here we have to be thinking 50 to 100 years down the road. A lot of other societies are. They will out compete us if we don't think that way."*
> **—Chris Rose, executive director, Renewable Energy Alaska Project**

"There are 2 billion people on the planet with no electricity … and many of them live in small communities very much like village Alaska," Rose said.

Smaller projects

There are a number of smaller-scale wind power systems around the state, including systems in the villages of Gustavus and Unalakleet.

Juneau Airport has installed a ground source heat pump, to save $85,000 per year by extracting energy from underground, while Tok school is installing a modern wood-fired boiler system, Rose said.

There are also some exciting possibilities for rural villages located on large, slow moving rivers, to use in-current turbine generators to harness energy from the rivers.

The village of Ruby on the Yukon River is using the first operational system of this type in the United States, Rose said. Experience in Ruby has identified improvements for the technology, and the resulting system design could be something suitable for export to the developing world.

"And of course the wave power and the tidal power potential in Alaska is tremendous," Rose said. "… This stuff is going to happen. These technologies work. … We can and should be world leaders in this stuff. … We're the only place in the United States where we can be doing demonstration projects and saving money at the same time."

Railbelt projects

In the Alaska Railbelt, Cook Inlet Region Inc. is moving ahead with its commercial-scale wind farm on Fire Island, adjacent Anchorage; Ormat Nevada has done some initial investigations into the potential for a geothermal power system adjacent Mount Spurr, on the west side of Cook Inlet; and people are reconsidering the possibility of building a major hydropower system, either on the Susitna River or at Lake Chakachamna, near Mount Spurr.

And there are other potential wind and hydropower sites that could provide power for the Railbelt, Rose said.

Energy policy

Against a background in which 29 U.S. states and the District of Columbia now have energy policies with renewable energy portfolios, the Alaska Legislature is considering a statewide energy policy, Rose said.

And bills at various stages in the state legislative process are addressing the funding of emerging energy technology development, the improvement of energy efficiency in Alaska public buildings and the creation of a state tax credit for renewable energy.

Both the House and Senate in Alaska are introducing omnibus energy legislation, pulling a lot of energy issues into one bill, Rose said.

> *Juneau Airport has installed a ground source heat pump, to save $85,000 per year by extracting energy from underground, while Tok school is installing a modern wood-fired boiler system, Rose*

Long-term decisions

Alaska is at a crossroads, where within the next five years the state needs to make major long-term decisions on its energy future, Rose said.

"As a society here we have to be thinking 50 to 100 years down the road," he said. "A lot of other societies are. They will out compete us if we don't think that way."

And within the next 100 years energy will need to become 100 percent renewable — it's a question of how fast to get there, Rose said.

"It's just a matter of time. The whole world is going to have to be moving this way, and that's what other places are doing," he said. ●

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● EXPLORATION & PRODUCTION

Bullish forecast for Western Canada

By GARY PARK
For Petroleum News

A late surge in oilfield service activity last year has prompted Calgary-based investment banker Peters & Co. to raise its 2010 target for Western Canadian drilling by 22 percent to 11,000 wells, far outstripping the leading industry forecasts.

It also hiked its total spending estimate for the basin by 28 percent to C$15.8 billion, up C$3.5 billion from its original prediction.

The end result would be a 40 percent utilization rate for the rig fleet, compared with a 34 percent target in the original forecast.

In the absence of any revisions, the other major well-count estimates for 2010 were: Canadian Association of Petroleum Producers 9,500, Canadian Association of Oilwell Drilling Contractors 8,278 and Petroleum Services Association of Canada 8,000.

Peters has tied its estimates to indications of an Edmonton par price of C$85.17 per barrel this year compared with C$77.19 last September when it released the initial target. Its gas price forecast for the AECO-C trading hub has also been boosted to C$5.72 per thousand cubic feet compared with C$4.60.

The stronger outlook for oil will be reflected in heavy oil drilling, which is expected to tally 2,300 wells in east-central Alberta and west-central Saskatchewan. Higher activity is also anticipated in the Bakken play of southeastern Saskatchewan.

But Peters holds out little hope of a rebound in conventional gas activity, which it believes will remain "challenged" through 2010, especially in shallow gas plays and coalbed methane in the southern region of Alberta.

Peters analyst Todd Garman said "companies with shallow drilling rig fleets and equipment rental entities will lag, as well as companies with equipment focused primarily towards conventional and mid-depth operations."

The report expects wells targeting gas will shrink to 55 percent this year from 60 percent in 2009 and 66 percent in 2008, but horizontal drilling, which dominates in shale plays, is forecast to account for 16 percent of all gas wells, up from 7 percent last year.

For the United States, Peters has boosted its forecast average number of working rigs to 1,350 from the September target of 1,200, but has lowered the average active gas rig count to 850 from 960, while hiking the number of oil rigs to 500 from 240.

Although many oilfield companies struggled to keep their heads above water in 2009, Peters' unweighted PE100 Oilfield Services Index of 25 companies rose by 37 percent, ending the year at 11,400, a significant gain from the 2008 level of 8,322 when the index dropped 41 percent. ●

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CORRECTION

A story in the Jan. 17 issue of Petroleum News incorrectly said BP Pipelines (Alaska) Inc. owns slightly more than 50 percent of the trans-Alaska oil pipeline. BP Pipelines owns about 47 percent.

—PETROLEUM NEWS

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GOVERNMENT

ACES hot topic as Legislature convenes

Some legislators concerned tax may be anti-competitive; some want more information; others want state to get something for changes

By KRISTEN NELSON
Petroleum News

Whether the Alaska Legislature will make changes in the state's oil and gas production tax this year is an unknown, but the tax was a popular topic as legislators began the 2010 session on Jan. 19.

The Department of Revenue has issued a report on how the current tax is working; the governor is proposing tax credit and other changes (see story in this issue); and one bill has been filed to reduce the tax rate.

Alaska changed its oil and gas production tax in 2006 from a tax on the gross, generally referred to as the Economic Limit Factor or ELF, to a tax on the net called the Petroleum Profits Tax or PPT, revised in 2007 with the passage of ACES, Alaska's Clear and Equitable Share.

Under ELF the tax was based on gross revenue, and the state received taxes even if the producers had no profit because of low oil prices. On the down side for the state, the ELF formula resulted in some fields paying very little production tax and when oil prices soared the state didn't benefit.

Under PPT and ACES production tax revenues reflect the price of oil: The state faces the risk of receiving no production taxes if oil prices are very low but it receives a larger percentage of profits when oil prices are high.

Producers complained about the regressive nature of ELF, under which they paid taxes even if they had no profit; with PPT and especially ACES the complaint is that the state takes too much of the upside — the benefit producers realize when oil prices are high — thus making Alaska projects uncompetitive and hurting investment in the state.

One of the goals of ACES was to encourage investment in Alaska by providing tax credits for certain work done in the state.

Issue in Juneau

The effectiveness of ACES was a frequent topic as legislators held the first press availabilities of the session Jan. 19 and 20.

House Speaker Mike Chenault, R-Nikiski, said Jan. 19 that he didn't know where legislators would end up on the oil tax this year.

"There's been a lot of interest in the House to at least have some questions asked," and some of those questions have already been posed to the governor, he said at a House majority press availability.

Chenault said he didn't think legislators were interested in a repeat of the recent "bloodbath" over tax changes, "but if that's what it takes to keep Alaska's economic driver moving down the road then I think there's a number of legislators that are willing to stand up … for Alaska and try to keep our economy moving."

He said he had some concerns with data on ACES from the Department of Revenue.

Chenault said he hadn't seen any reports, but understood that investment was said to be up in 2007, 2008 and 2009.

"But if you dig into the numbers and you find that most of that money was spent on maintenance — because there have been some pipeline integrity issues — and less on exploration, then maybe you get a clearer picture of whether the ACES program is actually incentivizing exploration instead of we're just spending more money on maintenance," he said.

Senate: Work needed

Senate President Gary Stevens, R-Kodiak, said at the Senate Bipartisan Working Group press availability later in the day that he thought there wouldn't be time in a 90-day session to revisit ACES.

Sen. Bert Stedman, R-Sitka, co-chair of Senate Finance, said the committee would start with the Department of Revenue forecast and look at the revenue picture and then "walk though those component parts (of ACES) so we get a good understanding of what works and what … may need some tweaking or quite frankly what may be broken. And then let a policy fall out of that analysis."

The Senate Finance Committee spent

see LEGISLATURE page 20

● EXPLORATION & PRODUCTION

'Foreigners' spur Alberta oil sands

By GARY PARK

For Petroleum News

Houston-based ConocoPhillips and Paris-based Total put the Alberta oil sands firmly back on track Jan. 19 by giving the green light to the second phase of their Surmont project.

The 50-50 joint venture will see production increased to 110,000 barrels per day from 27,000 bpd by 2015, employing 2,500 construction workers in the process and eventually tripling the permanent workforce to 300.

The partners did not release cost estimates, but Surmont's first phase cost about C$1.4 billion to come onstream in late 2007.

Production from the initial phase was about 20,000 bpd entering 2010 and is expected to ramp up over the next few years, said Matt Fox, president of ConocoPhillips Canadian unit.

ConocoPhillips is also a 50 percent owner of the Foster Creek-Christina Lake thermal oil sands project operated by Cenovus, sharing in current gross output of 115,000 bpd.

ConocoPhillips President John Carrig said in a news release that the oil sands are "an area of significant future oil production growth and are important for short- and long-term energy and economic security in North America."

C$300 million on technology

The company has already said it plans to spend C$300 million on heavy oil technology research and development over the next few years to improve economic and environmental performance.

Carrig said his company believes its oil sands projects, along with the conversion of oil sands' crude into fuel, can be conducted in "an environmentally sustainable manner and that technology will play a significant role in managing the environmental footprint."

As a result, he said, ConocoPhillips is committed to developing technology that "holds promise for reducing the impacts on air, land and water."

A ConocoPhillips spokesman said the decision to proceed was helped by company estimates that oil sands capital costs have come down over the past year.

Total also working Joslyn

Yves-Louis Darricarrere, Total's president of exploration and production, said the "responsible development of Canada's oil sands, particularly with respect to the environment, will be crucial in providing a secure source of energy for the future."

"Total is pleased to be advancing on this project and plans to bring to it innovation and global expertise in world-class heavy oil projects, while meeting the strict national and international standards for environmental compliance," he said.

Through its Canadian subsidiary, Total is also planning mining operations at its Joslyn bitumen lease and an upgrader near Edmonton.

The Alberta Energy Resources Conservation Board plans to start hearings Feb. 24 on the 150,000 bpd upgrader facility, which is designed to double in the second phase.

But a final corporate decision by Total won't come until after the 200,000 bpd Joslyn mine also gains approval, probably in late 2011.

Jean-Michel Gires, president of Total E&P Canada, told the Edmonton Journal his company is making a long-term bet on the oil sands, anticipating an operating life for the upgrader of 30 to 40 years. ●

Contact Gary Park through publisher@petroleumnews.com

● PIPELINES & DOWNSTREAM

Fledgling producer protests tariff hike

Cook Inlet Energy, having just bought a package of oil and gas properties, fights pipeline company's 259 percent rate increase

By WESLEY LOY

For Petroleum News

Less than a month after regulators invited interested parties to jump into a case involving a steep tariff increase for shippers on a pipeline in Alaska's Cook Inlet, one oil producer has filed a formal challenge to the hike.

Anchorage-based Cook Inlet Energy LLC on Jan. 12 filed a petition to intervene with the Regulatory Commission of Alaska. The company's attorney, Robin Brena, two days later also filed a 24-page "statement of position, formal complaint, and protest."

The protest argues Cook Inlet Pipe Line Co.'s 259 percent rate increase — from $4.06 per barrel of oil to $14.57 per barrel — is "excessive, unjust, and unreasonable."

The protest also says the hike "could not have come at a worse time" for Cook Inlet Energy, which in late 2009 purchased an assortment of oil and gas assets on the west side of Cook Inlet from Pacific Energy Resources Ltd., a California independent undergoing a bankruptcy liquidation. The assets include the West McArthur River oil field and the Osprey offshore oil platform in the Redoubt unit.

"For a small company such as CIE, the financial consequences of a $10.51 per barrel rate increase will be substantial," Cook Inlet Energy's petition to intervene says. "CIE's goal is to expand its current production of 120 barrels per day of crude oil from the west side of the Cook Inlet to 1,100 barrels per day or more by the end of 2010. Having to incur an excessive, unjust, and unreasonable transportation rate while also taking the risks and incurring the investment necessary to expand its production on the west side of the Cook Inlet is a potentially huge burden on CIE."

Volcano damage

Texas-based CIPL operates a 20-inch pipeline that runs 42 miles from Granite Point southwest along the western bank of Cook Inlet to the Drift River Oil Terminal, which also belongs to CIPL. The pipeline was installed in 1966.

Chevron subsidiary Unocal owns half of CIPL, while Pacific Energy holds the other half.

The RCA, in a 12-page order issued Dec. 28, approved CIPL's rate increase, at least temporarily, and invited oil producers or others to challenge it and possibly win refunds. The order allowed CIPL to start collecting $14.57 per barrel of oil effective Jan. 1.

The RCA said that although the rate hike is "significant," it appears CIPL calculated it "in accordance with" a methodology established in a 2001 state settlement the commission accepted.

CIPL attributes much of its rate increase to volcanic eruptions of nearby Mount Redoubt, which caused extensive damage, idled west Cook Inlet oil production and the pipeline for much of 2009, and forced costly measures to protect the Drift River Oil Terminal and the crude in storage there.

In a recent RCA filing, CIPL said its higher rate is "entirely reasonable," allowing for recovery of actual costs plus a reasonable return. CIPL added it "has no responsibility to subsidize the recent investment" Cook Inlet Energy made in the oil and gas properties.

'Way out of line'

Brena, the attorney for Cook Inlet Energy, raises multiple arguments against CIPL's higher tariff.

First, the settlement between CIPL and the state is "legally irrelevant" to Cook Inlet Energy's right to challenge rates, as the producer wasn't a signatory to the settlement, Brena argues. Further, he notes that the standard for acceptance of a settlement is "much less stringent" than the standard for establishing just and reasonable rates.

Brena also cites a lack of evidence to support CIPL's claimed costs, and says about a third of the company's proposed 2010 cost of service is a pass-through of expenses from past years. That's OK among settling parties, but it "violates several ratemaking principles" when applied to a nonsignatory shipper, Brena argues.

As for the volcanic eruptions, CIPL, in accordance with prior RCA orders, should have had insurance to protect its ratepayers from an extraordinary event, Brena says.

"The particular location of CIPL's assets puts it at risk from a Mt. Redoubt eruption," the protest filing says. "It is incumbent upon CIPL to either insure or self-insure against this risk of loss, and not directly pass on the losses to the ratepayer in extraordinary high rates."

Brena also questions CIPL's projection for sharply lower pipeline throughput, and says CIPL's operating expenses "seem way out of line." He notes that CIPL isn't even operating its Drift River tank farm and pumps, leaving producers to push crude directly to tankers.

"Notwithstanding the fact that a significant percentage of CIPL's assets are not in service or providing any benefit to its shippers, CIPL's operating expenses are increasing," including higher salaries and employee benefits, Brena writes.

Other complaints

The RCA plans to set a final rate for the pipeline, and has opened a docket to consider the matter.

Two other parties also have taken issue with CIPL's rate hike.

ExxonMobil, which holds a 75 percent working interest in the Chevron-operated South Granite Point unit, filed a brief statement with the RCA objecting to the tariff increase.

Dan Donkel, an overriding royalty interest owner in the Redoubt unit, filed a petition to intervene on Jan. 12. ●

Contact Wesley Loy at wloy@petroleumnews.com

● FINANCE & ECONOMY

Canada poised for strong M&A year

By GARY PARK

For Petroleum News

On the heels of a blockbuster year, mergers and acquisitions in Canada's energy sector are forecast to enjoy at least a repeat performance in 2010.

Led by the US$18.4 billion Suncor Energy takeover of Petro-Canada, Canada racked up US$51.9 billion in deal making in 2009, up 19 percent from 2008, reports Mergermarket, which follows global M&A activity.

The report said market consolidation accounted for 84 percent of the deals between Canadian companies.

It is counting on shale gas remaining a hot target.

Calgary-based Sayer Energy Advisors delivered a less bullish report on 2009, rating the enterprise value of energy M&As at C$47 billion, assigning C$20 billion to the Suncor-Petro-Canada deal, which it said put 2009 on a par with 2008.

Sayer analyst Crystal Holdershaw is predicting an uptick in 2010 value because of several large asset packages hitting the street already this year.

"There will be more consolidation throughout the industry," she said, which more companies subscribing to the notion that bigger is better "if they want to raise money and survive."

Suncor divestitures

Suncor expects to make divestitures of C$2 billion-C$4 billion in the next year or two — some of it involving U.S. Rockies' gas assets inherited from Petro-Canada — as it lowers company gas output to 450 million-500 million cubic feet per day from its current 750 million cubic feet per day.

Investor relations manager John Rogers, explaining Suncor's haste to unload conventional assets, told a BMO Capital markets conference in New York earlier in January that the company is "all about oil sands."

Talisman Energy has assets producing almost 2,800 barrels of oil equivalent per day on the block; PetroBakken Energy is looking for bids on 6,750 boe per day; and Cenovus Energy, the oil sands spin-off from EnCana, said it plans to sell a significant amount of assets in 2010.

Holdershaw said the big question now is who is capable of buying such packages.

In the absence of domestic players with the capital backing, she suggested international companies will likely be among the buyers.

She forecast that corporate transactions, which accounted for about 80 percent of M&A deals in 2009, will decline as the "focus shifts back to larger property transactions."

As well, she predicted that the interest among big international companies in gas packages might be piqued.

Smaller packages might be more attractive to more players

Because of the appetite for smaller packages, Holdershaw said it "might be prudent" for majors to consider breaking up their packages to draw more interest from a greater number of players.

Holdershaw said she did not expect any improvement in the limited access to capital for both public and private junior companies, especially now that banks — who held the credit lines for their clients in 2009 — are losing hope that gas prices will improve and reserve values will increase.

She said gas-weighted companies "may be making enough money to keep the lights on, but not enough to replace the depleted reserves. Banks will then force some companies to sell their assets or merge with other companies in order to get loans repaid."

For now, however, she said not many companies are known to be for sale or to be weighing strategic alternatives to maximize shareholder value, but it is likely a number of companies are "quietly exploring" alternatives in order to survive.

More companies in trouble

The number of companies seeking creditor protection or entering receivership will continue to build in 2010, especially among those "that hung on by a thread in 2009."

If forecasts by the Bank of Canada and Finance Minister Jim Flaherty are accurate and interest rates rise in 2010 that will negatively impact M&A prices, Holdershaw said.

Interest should remain strong in resource plays such as Montney and Horn River in British Columbia, Bakken, Kindersley Viking and Lower Shaunavon in Saskatchewan and Pembina Cardium and Duvernay in Alberta, she said.

The report predicts prices will be greater than C$50,000 per boe for oil-weighted transactions, but only C$20,000-C$30,000 per boe for gas-weighted transactions and, with the large amount of gas assets now up for sale, larger deals could skew the median acquisition price.

The one possible upside for gas assets could be an overhaul of the Alberta government's gas royalty structure, Holdershaw said. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

Wainwright CBM needs additional testing

Program in 2009 confirmed extent of resource but ran into a glitch with the production testing; team plans to return this summer

By ALAN BAILEY
Petroleum News

The Chukchi Sea coastal community of Wainwright doesn' t know yet whether the rich seams of coal sitting a couple of thousand feet or so under the village can produce natural gas as a replacement for expensive diesel oil and heating oil, for power generation and keeping buildings warm.

As part of a multiyear project to test the feasibility of producing coalbed methane in the village, a U.S. Geological Survey and U.S. Bureau of Land Management team, supported by the North Slope Borough, Arctic Slope Regional Corp. and Olgoonik Corp., found a promising coal seam in an exploratory well in the village in 2007, returning the following year to drill a pattern of wells for a production test from the seam. The team went back to Wainwright in the summer of 2009 to conduct the production test and drill some further delineation wells, to verify the extent of the potential coalbed methane resource.

But, while the 2009 delineation drilling confirmed the lateral extent of the target coal seam, the production test hit some snags that will require the team to return to Wainwright in May or June of this year, to hopefully demonstrate that gas can be produced at viable rates in the village, Art Clark, USGS drilling project supervisor and co-project leader , told Petroleum News Jan. 13.

Two delineation wells

In 2009, using a truck-mounted rig that the team had airlifted into Wainwright in 2008, the team drilled two delineation wells, one about two miles northeast and the second about half-a-mile south-southwest of the original 2007 well, Clark said. Those delineation wells, drilled as far out from the 2007 well as the Wainwright road system would allow, confirmed that the coal seam discovered below the local permafrost at a depth of 1,250 feet in 2007 maintains a thickness of seven to eight feet from one well to another. And, although the team is still desorbing gas from coal samples from the delineation wells, results to date suggest that the gas content of the coal is consistent with that found from the 2007 drilling.

"The reservoir seems to be laterally continuous and appears to hold approximately the same amount of gas that we got from our 2007 well," Clark said.

Unfortunately, however, the 2009 production test did not proceed as smoothly as the delineation drilling.

Reduce pressure

The idea behind coalbed methane production is to pump water from a coal seam, to release gas from the seam by reducing the pressure. And in the case of Wainwright the team placed a submersible pump down a central production well, while placing sensors in four surrounding monitor wells to measure the impact of gas production on the reservoir.

"Everything started out pretty good for about two days and then we started getting a bunch of water and (methane) hydrate ice pumping from the well," Clark said. "So we were just pumping out slush after a while."

To melt the ice the team bought two custom-made, 1,200-foot lengths of heater cabling — the type of cabling that people living in cold climates use to melt ice from house roofs and guttering — and ran one length of cable down the outside of the well draw pipe and one length down the inside of the pipe. The cabling required a special 220-volt power supply and was of a length that pushed the limits of what the cable manufacturer could produce, Clark said.

But it worked.

"Once we got those up and running we pretty much eliminated our icing issues," Clark said. "The water was still very cold, but we were getting water and gas."

The test then made good progress for a few days until the fluid level in the well dropped to a certain point.

"As the fluid level came down, all of a sudden we started losing the gas production and the water production … and we lost hydraulic, or pressure, communication through the reservoir to our monitor wells," Clark said.

On the Web

See previous Petroleum News coverage:

"USGS plans CBM tests at Wainwright," in May 3, 2009, issue at www.petroleumnews.com/pnads/501081540.shtml

"More Wainwright coalbed methane drilling in works," in June 8, 2008, issue at www.petroleumnews.com/pnads/30789112.shtml

"Wainwright test well finds gas," in Nov. 4, 2007, issue at www.petroleumnews.com/pnads/516981573.shtml

The team plans to return to Wainwright in the coming summer to try to resolve the production problem by stimulating the well, using a reservoir fracturing technique.

Stop and start

The team found that it could restore pressure communication with the monitor wells by filling the production well with a mixture of antifreeze and water (water , by itself, would have frozen in the well). It then became possible to re-start production, although as the fluid level dropped the production clogged up again.

Eventually, the team tried dropping the well pressure for about 30 days, to see what would happen, but it failed to entice much more than a trickle of oil and gas from the well.

"We're still not exactly sure what happened, but we worked through the end of August and never were able to conduct a good production test," Clark said. "We just continuously had problems."

Clark said that the team has developed a couple of theories about what happened but that he is certain that the problem is associated with some form of reservoir damage and associated clogging around the production well bore — production fully met expectations until the fluid level dropped.

"I absolutely do believe that we have a problem with the well," Clark said. "I don't think it's a problem with the producability of the reservoir."

The team plans to return to Wainwright in the coming summer to try to resolve the production problem by stimulating the well, using a reservoir fracturing technique.

"We haven't decided exactly how we're going to do it, but we're going to clean out the well, stimulate it, try to open up the near-bore fraction of the coal through some type of fracturing," Clark said. ●

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● FINANCE & ECONOMY

ACES: working well but needs adjustment

Parnell says that the tax credit rules could be improved to provide further exploration and development incentives; no rate changes

By ALAN BAILEY
Petroleum News

When on Jan. 14 Alaska Gov. Sean Parnell announced his administration's proposals for some changes to the state's ACES oil production tax, he said that he is conscious of industry's need for a stable tax regime but that he has also remained open to the possibility of changes in ACES, if those changes can be justified.

JUDY PATRICK

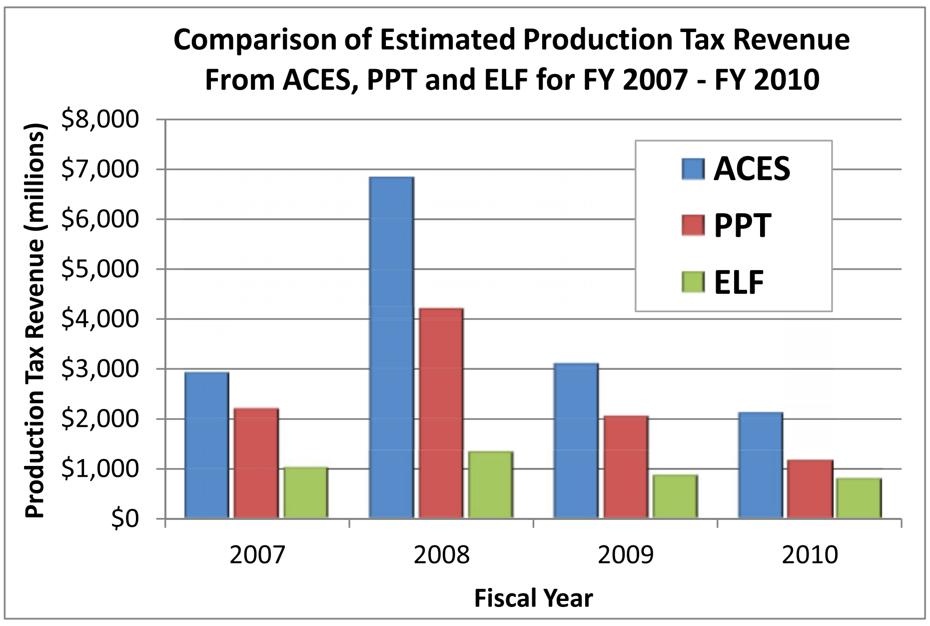
SEAN PARNELL

But, the ACES tax has been operating as intended, he said.

"Since the passage of ACES we have verified that our net tax, which only taxes oil companies on profits, did what it was supposed to do when oil prices spiked and (then) plunged during the period immediately after ACES was passed," Parnell said. "When oil profits were extremely high, the state's share of the revenue stream was high. When oil profits were low, the state's share was likewise much smaller."

Economic model

Parnell said that in August he asked the Department of Revenue to show him its economic model, to enable him to verify that the tax was giving the state its fair share of oil revenue and to evaluate the operation of the ACES tax credits in attracting more jobs for Alaskans. But Revenue had already been analyzing public and confidential company data, to gain insights into how recent company investments compared with past investments, he said.



ALASKA DEPARTMENT OF REVENUE

The Alaska Department of Revenue has calculated that ACES has resulted in higher state revenues than either of the previous state production tax arrangements (PPT and ELF) would have done over the period during which ACES has been in operation.

"We've been open to industry's communications about what they felt was working with ACES and what was not working with ACES," Parnell said. "I personally talked with many of the oil company employees and executives, and members of the Alaska Oil and Gas Association board, to get their views on Alaska's tax regime."

Parnell said that the Department of Revenue used the information that it gathered to prepare an ACES status report and that he had asked Revenue Commissioner Patrick Galvin to use the findings in the report to formulate recommendations for any ACES changes that might result in increased oil investment and more jobs for Alaskans.

Four recommendations

Galvin made four recommendations for what Parnell characterized as "refinements" to the ACES statute, and Parnell has endorsed those changes for submission to the state Legislature in the 2010 legislative session. The proposed changes are:

- To make available to in-field, well-related activity, such as infill drilling, the 30 percent tax credit currently available for exploration activities more than three miles from an existing well.
- To enable companies to use all of their capital credits in the year that the credits are earned, rather than having to defer the use of at least half of the credits into the following year.
- To enable new explorers to claim tax credits for exploration costs without having to make subsequent investments equal to the value of the credits.
- To waive state claims for interest on additional taxes that a company might have to pay in arrears, as a consequence of the retroactive application of ACES tax regulations that the state is currently finalizing.

The 30 percent tax credit for in-field activities would translate to a $250 million to $350 million benefit to the oil industry in the current fiscal year, with that benefit being obtained in exchange for investments in Alaska that would create hundreds of new Alaska jobs and benefit the development of North Slope heavy oil, Parnell said. And accelerating the use of capital credits into the year in which they are earned would confer another $250 million in benefit to industry in the year that it becomes effective, he said.

The proposal to enable new explorers to claim tax credits up front would put those explorers on "a fair and level playing field" with companies that already have oil production in state, while the waiver of interest on some underpaid taxes would "be a matter of fairness," given the retroactive application of the ACES regulations, Parnell said.

No rate changes

The state administration does not propose making any changes to the ACES tax rates.

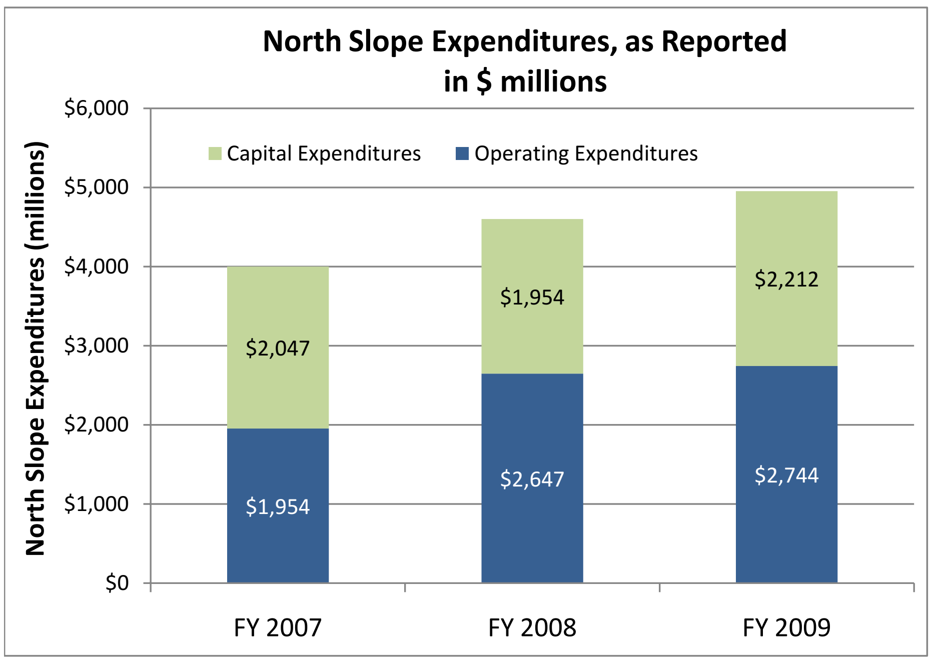
The administration's discussions with oil companies failed to reveal any evidence that the lowering of the progressive tax rates in ACES would result in new investments and new jobs in Alaska, regardless of claims that lower rates would make Alaska more competitive for those investments, Parnell said. Lowering the tax rates would simply provide the oil companies with more money to invest wherever they wish.

"At this moment I am working for providing more opportunity for Alaskans in jobs," Parnell said. "I'm not interested in changing progressivity so they (the companies) can take that money and invest it somewhere else. If they're willing to invest it here, I'm open to considering it, but I'm standing up for Alaskans in this, not some other country."

Revisit 2007 analysis

The original impetus for Revenue's investigation of the impact of ACES was a desire to revisit the 2007 analysis of the previous tax system, known as PPT, said Commissioner Galvin. That original analysis had led to the development of the

see ACES page 11



ALASKA DEPARTMENT OF REVENUE

Alaska North Slope oil industry capital and operational expenditures have both increased since the state's ACES production tax came into operation.

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ACES

ACES tax.

"I wanted … to look at how ACES is performing under the same type of analysis, looking at the balance between revenue generation and those investment incentives that were a key part of the ACES proposal," Galvin said. And one purpose of the analysis was to address a public debate about whether the new tax was acting as a disincentive for new oil and gas investment, he said.

The Revenue investigation has concluded that oil revenues have been higher during the past two-and-a-half years than they would have been if PPT or the system previous to that (referred to as "ELF") had been in place, Galvin said. And during that same period company spending, both in terms of capital investment and operational spending, also increased.

PAT GALVIN

Operational expenditure climbed initially but has leveled off in the past year, paralleling oil industry costs that rose dramatically with the price of oil and then came down somewhat as oil prices dropped, Galvin said. Oil industry capital expenditure usually tends to track the price of oil, but capital expenditure estimates and projections for Alaska have remained on an upward trend in the past year, despite the decline in oil price, he said.

Moreover, the 2007 run-up in maintenance and pipeline replacement costs resulting from Prudhoe Bay pipeline problems in 2006 did not contribute to a continuing increase in capital and operational expenditure, Galvin said.

"Jobs are also up," Galvin said. "In fact the jobs in the oil and gas industry in Alaska are at the highest level in history."

Many factors

However, although oil industry spending is up, it is too early to attribute that increase to ACES, especially since there are so many factors that influence industry investments, Galvin said.

Galvin also pointed out that a standard tax deduction that had applied to expenses associated with the Prudhoe Bay and Kuparuk River units when calculating ACES taxes expired at the end of December, thus placing these two units under identical tax rules to other North Slope units from the start of 2010.

"This (standard deduction) provision … was intended to moderate the risk associated with adopting a profits based tax without substantial historical data on which to rely for future cost estimates," the Department of Revenue said in its ACES status report.

The standard deduction substantially increased the state's tax revenues, especially in 2008 when oil prices were particularly high, the report said. Conversely, the demise of the standard deduction will now put more money into the companies' pockets, Galvin said.

Influencing decisions

Reports and anecdotal information from industry indicate that incentives available under ACES are directly influencing decisions made by some exploration companies, Galvin said.

"That's an important consideration for us in terms of recognizing that on the exploration side they do seem a driver of those investment decisions," he said.

Hence, the motivation to adjust the ACES tax credit provisions, with changes such as the wider application of the 30 percent tax credit rate.

Marcia Davis, deputy commissioner of the Department of Revenue, explained some of the details of that particular proposed change, saying that some capital expenditure within an oil field currently qualifies for an ACES tax credit of 20 percent. The proposed extension in the scope of the ACES 30 percent tax credit rate would apply that rate to in-field well work, some of which currently qualifies for credits at the 20 percent rate and some of which does not currently qualify for any tax credit, she said.

The Revenue investigation of ACES uncovered some areas in which the administration of ACES could be improved, especially with regard to the complexity of tracking tax credits over more than one year, to the lack of accounting for the time value of money when the use of credits has to be delayed and to the need to be fair to new explorers in terms of their ability to use tax credits, Galvin said.

And the lengthy time required to complete ACES regulations, with the subsequent proposal to waive the state's interest on some unpaid back taxes, resulted from the state using a regulation development process that was highly interactive with industry, to ensure practical, understandable and usable regulations, Galvin said.

But, having assessed the impact of ACES within Alaska, the Department of Revenue is embarking on an analysis of how Alaska's oil-tax regime compares with regimes elsewhere in the world in terms of competing for investment, Davis said.

"That is a second phase of what we're looking at, and we'll start to be able to respond to questions on how Alaska compares to other jurisdictions," she said. ●

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OUR ARCTIC NEIGHBORS

Norway ministries clash over development

Norway's Ministry of Petroleum and Energy should not expand the next Awards in Predefined Areas licensing round to the Barents Sea because several of the new areas proposed by the government are close to the coast and particularly vulnerable, Norway's Climate and Pollution Agency said in a release Jan. 7. CPA is part of the Ministry of the Environment.

"We generally believe that all the proposed drilling areas in the Barents Sea should be announced through regular licensing rounds. In those cases the treatment of each case will be more thorough," said Signe Namdal of the CPA. In Norway's regular licensing rounds companies nominate blocks where they would like to explore for oil and gas. In the APA rounds the government defines the blocks in advance.

The CPA argues that there is little knowledge about the natural resources in some of the proposed areas.

"Good knowledge about natural resources and vulnerability should be considered as important as good knowledge about geology before an area is singled out for energy development in this plan for allocation of predefined areas," Namdal said.

Examples of areas that the CPA is concerned about include the Finnmark East and West blocks, located at 71 degrees latitude, which are in areas that may be vulnerable in parts of the year, according to the release.

The CPA recommends that thorough surveying should be carried out there before the blocks are made available, including mapping and assessment of fauna and seabed conditions.

The APA system ensures that very large areas close to existing and planned infrastructure are available for the industry, the Norwegian Petroleum Directorate said on its Web site. The APA area will be expanded as new areas mature, but the area is not

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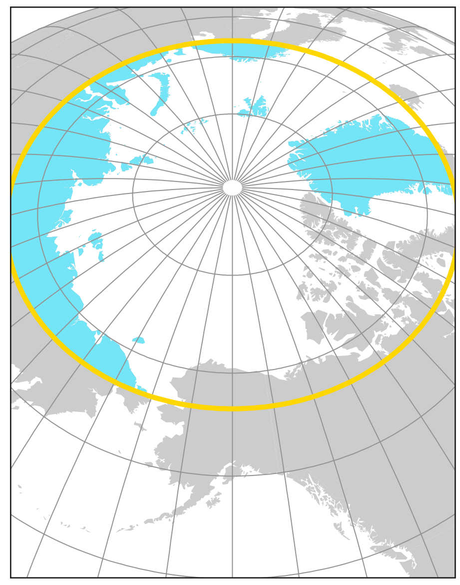
● OUR ARCTIC NEIGHBORS

Norwegians want more study of Lofoten area

Oil industry association thinks it's good news that a majority would like to research the petroleum potential of far northern waters



By SARAH HURST
For Petroleum News

Norwegians have a positive attitude toward the oil and gas industry and most would like to see more petroleum studies in the controversial Lofoten area, according to a new survey conducted by global market research company Synovate for the Norwegian Oil Industry Association. The association published the results of the survey in a release Jan. 14.

Eight out of 10 respondents said they believe that the oil and gas industry will have major significance for society and business development in northern Norway. Seven out of 10 want more petroleum studies in the Lofoten area, which is a thriving fishery and currently closed to drilling. Seismic studies have been conducted in the Lofoten area over the past few years, but the results remain confidential. A new management plan for the area will be presented this year, and the issue has the potential to break up the coalition government of Prime Minister Jens Stoltenberg.

"It is quite natural that the majority want knowledge on the table," said Gro Braekken, the head of the association. "The study shows clearly that Norwegians want to know more about the consequences of oil and gas activities outside Lofoten and Vesteralen. We are also pleased that people agree the activities will make a positive contribution to society and business development," she added.

Center Party opposes EIS

The leader of Norway's Center Party, Liv Signe Navarsete, said recently that she opposed conducting an environmental impact statement for the Lofoten area.

"As a responsible politician Navarsete should contribute to enhancing knowledge of the country's main industry rather than being anxious to shut the door to future value creation," Braekken said.

"For 40 years the Norwegian oil and gas industry has contributed to increased welfare for the individual Norwegian, innovative employment opportunities and world-class technology development," Braekken continued. "We must continue to build on the knowledge we have built up in order to ensure that also in the future Norway will be the world's best country for each and every one of us to live in."

The study also found that 85 percent of the Norwegian population has a very good or fairly good impression of the oil and gas industry. Almost as many believe that the industry has given Norwegians a higher standard of living.

"We can see that people are proud of what Norway has achieved as an oil and gas nation," Braekken said. "At the same time we are experiencing a debate, not least among key politicians, in which the industry will be talked down. The fact is that oil and gas will be an important energy source for many, many years ahead. ... Our country needs the ability to exploit the resources we have in the best possible way." ●

● PIPELINES & DOWNSTREAM

Tugs take ExxonMobil oil tanker in tow

Ship loses power as it departs Prince William Sound with Alaska crude; Sen. Murkowski says incident proves need for dual escorts

By WESLEY LOY

For Petroleum News

Two escort tugs took an oil-laden tanker under tow in Alaska's Prince William Sound on Jan. 17 after the ship experienced a power loss following what the operator said was an electrical problem.

Authorities soon allowed the ship to continue its voyage to San Francisco, clearing it to depart the Sound the next day.

The double-hulled tanker Kodiak is operated by Houston-based SeaRiver Maritime Inc., which carries Alaska North Slope crude for ExxonMobil.

Two Crowley-operated tugs, the Aware and the Tan'erliq, were escorting the tanker and came to its assistance, reported the Prince William Sound Regional Citizens' Advisory Council, a Valdez-based oil industry watchdog group.

The 869-foot tanker was carrying 610,000 barrels of crude and was outbound at Hinchinbrook Entrance, where the Sound opens into the North Pacific Ocean, when the tanker crew noted "what proved to be an overheating of an electrical component of a turbo generator," SeaRiver spokesman Ray Botto said in a written statement.

The problem developed just before 3 a.m.

"There was no fire. There were no injuries or pollution," Botto said.

Botto told Petroleum News by phone the turbo generator draws steam off the main engine to make electric power. As the ship switched over to another generator, the steam plant that drives the tanker lost power, not unlike what happens when you turn off a boiling kettle, Botto said.

The crew opted for a tow "as a precaution," he said.

Both tugs were able to quickly attach tow lines to the tanker and move it to Knowles Head, a safe anchorage well inside the Sound.

After a U.S. Coast Guard inspection, the tanker was cleared to depart at 8 a.m. Jan. 18.

Joel Kennedy, maritime operations project manager for the RCAC, said in a written update that SeaRiver informed him the ship was without propulsion for about 30 minutes.

RCAC spokesman Stan Jones said his organization was pleased to see the escort tugs were there and performed well.

"It was exactly what they were invented to do," he said.

U.S. Sen. Lisa Murkowski, R-Alaska, said the incident provides impetus for legislation the Alaska congressional delegation is pushing to mandate dual tug escorts for double-hulled tankers, and not just single-hulled ships as the law now specifies.

In recent years the tanker fleet has been transformed, with virtually every ship in the Alaska trade now equipped with a double hull to reduce chances of a major spill.

Murkowski said that "even though it is rare for a tanker to lose power, this is not the first time it has happened and it won't be the last. We must maintain the present escort system indefinitely."

While the other major North Slope oil producers, ConocoPhillips and BP, chose to build new fleets of tankers to meet the double-hulled standard imposed after the Exxon Valdez disaster of 1989, ExxonMobil went with legacy ships to replace its single-hull tankers.

Built in 1978, the Kodiak formerly was named the Tonsina and was part of a fleet hauling Alaska oil for BP. ExxonMobil acquired the ship in 2005, re-christened it the Kodiak, and refurbished it in a Singapore shipyard.

ExxonMobil also acquired another tanker from the BP fleet, the Kenai. It, too, was refurbished and given a new name, the Sierra.

"There is absolutely nothing wrong with those ships," Anil Mathur, who runs BP's shipping affiliate, said in 2005.

The Kodiak will be checked out further, Botto said, though he couldn't say in what port. ●

Contact Wesley Loy at wloy@petroleumnews.com

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ARCTIC NEIGHBORS

to be reduced, the directorate said.

—SARAH HURST

Statoil resumes shipping of Snohvit gas

Production from Statoil's Snohvit natural gas project in the Barents Sea resumed in mid-December after the four-month shutdown of the Melkoya liquefied natural gas plant ended, the Norwegian company said in a release Jan. 5. The third cargo dispatched after production started again left Melkoya Jan. 4, and the LNG vessels are back in regular operation.

The Melkoya plant had been closed for upgrading and maintenance. The maintenance shutdown was completed in early November, but startup was delayed by problems affecting the facility's large motors, which form a central part of the refrigeration process. The defective motor has now been replaced by a reserve unit that was in store in Hammerfest.

"These have been demanding months for all involved at Melkoya," said Knut Henrik Dalland, Statoil's senior vice president for production. "Hammerfest LNG plant is a highly advanced facility where huge efforts have been made to solve complex technical problems." The plant's total capacity will now be verified in a forthcoming performance trial, Dalland said.

At peak production an LNG tanker will depart from Melkoya every five or six days, with each vessel transporting almost 5.3 million cubic feet of LNG to customers worldwide.

"LNG from Snohvit provides us with the flexibility to market gas all over the world," said Richard Eriksen, who heads LNG trading and operations in Statoil.

Snohvit is the first development in the Barents Sea and Melkoya is the world's northernmost LNG facility.

—SARAH HURST

EXPLORATION & PRODUCTION

DEC proposes new Nikaitchuq air permit

The Alaska Department of Environmental Conservation is planning to issue a new air permit to Eni Petroleum for ongoing work at the onshore-offshore Nikaitchuq project.

The new permit would include offshore facilities currently under construction in the Air Quality Control Minor Permit originally granted for the project nearly five years ago.

The state originally issued the permit to Kerr McGee Oil & Gas Corp., the Denver independent that first sanctioned development of Nikaitchuq in 2006, and then revised the permit when Italian major Eni acquired the prospect around the same time.

Kerr McGee planned to develop Nikaitchuq in two phases — an onshore production pad at Oliktok Point followed by a future offshore pad — and only permitted the first.

Concurrent development

Eni is developing the prospect concurrently from onshore and offshore facilities, requiring modeling and studies to gauge the air quality impacts of the additional pad.

According to the state, Eni "requested to revise the emission unit inventory, ambient air quality protection requirements, and Owner Requested Limits (ORLs) to avoid Prevention of Significant Deterioration (PSD) classification" from the original permit.

Since its original revision, Eni submitted but withdrew two other air permit applications.

Eni is currently anticipating first oil from the onshore facilities at Nikaitchuq by the end of 2010, with first oil from the artificial offshore gravel island to follow.

—ERIC LIDJI

● EXPLORATION & PRODUCTION

Point Hope appeals Shell Chukchi drilling

By ALAN BAILEY

Petroleum News

In a move that has become de rigueur in response to any government agency decision supporting Shell's much-frustrated plans to drill in the Alaska Arctic outer continental shelf, the Native Village of Point Hope and eight environmental organizations filed suit in the U.S. Court of Appeals for the 9th Circuit on Jan. 19, appealing the U.S. Minerals Management Service approval of Shell's 2010 exploration plan for the Chukchi Sea. Shell plans to drill up to three wells in the Chukchi during the 2010 open water season.

The MMS analysis of the environmental impacts of Shell's planned activities was "sorely lacking," said Earthjustice, a law firm that represents environmental groups.

The MMS analysis of the environmental impacts of Shell's planned activities was "sorely lacking," said Earthjustice, a law firm that represents environmental groups.

"The U.S. Department of the Interior's Minerals Management Service approved drilling in the Chukchi Sea after doing only an abbreviated and internal review of its potential harms and despite significant concerns surrounding Shell's oil leases," Earthjustice said. "… Under Shell's plan, a huge 514-foot-long drill ship and an armada of support vessels and aircraft would patrol the waters of the icy Arctic Ocean, generating industrial noise in the ocean, emitting tons of air pollutants, including heat-trapping gases, and thousands of barrels of water pollutants. The Chukchi Sea is habitat for endangered bowhead whales, threatened polar bears, walrus and a host of other wildlife — many of which are vital to sustaining the thousands-year old subsistence way of life of Alaska Native coastal communities."

Shell defended the MMS decision.

"It's our belief the MMS was thorough in its technical and environmental evaluation of our 2010 Chukchi exploration plan and that Shell has demonstrated its ability to operate in the Arctic in an environmentally responsible manner," said Shell spokesman Curtis Smith. "A tremendous amount of work went into writing and evaluating this permit and we fully expect the MMS to be successful in defending its approval."

Smith said that Shell must drill in its Chukchi Sea leases to evaluate the potentially prolific hydrocarbon resources of the Chukchi Sea, resources that could play a major role in reducing U.S. dependence on foreign oil, provide thousands of jobs and help extend the life of the trans-Alaska pipeline.

"Shell has gone to great lengths to minimize the impact of both its Chukchi and Beaufort drilling programs, including a voluntary shutdown during the fall subsistence whaling harvest in the Beaufort Sea, installing best available discharge technology, and aspirations for a reduced number of wells," Smith said. "These steps were taken after considering direct feedback from North Slope stakeholders who asked that Shell take a measured approach to offshore exploration."

MMS declined to comment on the lawsuit until it sees the filings in the case. ●

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● SAFETY & ENVIRONMENT

Exxon oil persistence may be explained

Study finds crude from Exxon Valdez oil spill trapped in layer of compacted beach sediment which prevents it from easily degrading

By ELIZABETH BLUEMINK
Anchorage Daily News

For nearly a decade, scientists have puzzled over the persistence of oil from the Exxon Valdez oil spill.

A pair of Lower 48 researchers on Sunday published the first study to attempt an explanation for why that oil isn't degrading as much as expected.

Their findings have implications for any future attempt to remove residual oil from the beaches — a proposal launched by state and federal prosecutors in 2006 that is still being negotiated with Exxon Mobil Corp.

An estimated 21,000 gallons of the 11 million gallons of crude the Exxon tanker spilled in Prince William Sound in 1989 remain on Alaska beaches.

For years, federal and state officials expressed optimism that the oil from the massive spill would dissipate completely. In fact, in the first five years after the spill, scientific testing did show oil was degrading at a fast clip. Prince William Sound's beaches started to look idyllic again, even though people — and animals — digging below the surface still could find oil.

Since then, federal scientists have gathered evidence that disputes spill cleanup officials' prediction that all of the toxic oil would disappear in a few years. Further, the scientists say, the rate at which the oil is disappearing from the beaches has slowed down.

Oil trapped

That's because the rest of the oil is trapped in a layer of compacted beach sediment where it cannot easily degrade, said Michel Boufadel, the lead researcher of the $1.2 million study, funded by the Exxon Valdez Oil Spill Trustee Council. The study is being published in Nature Geoscience, a monthly scientific journal. Boufadel runs the Center for Natural Resources Development and Protection at Temple University's College of Engineering, and specializes in studying the movement of oil in water.

His testing over the past three summers in Prince William Sound showed that its gravel beaches consist of two layers: an upper layer that is highly permeable to water, nutrients and oxygen, and a lower layer that isn't, he said.

Exxon oil that nearby freshwater sources didn't flush out to sea slowly trickled into the lower layer and got stuck, he said.

In its recent report, the council said it can identify 50 beach segments — a total length of about 1.6 miles — where a significant amount of oil remains buried.

The Temple University tests occurred on Smith, Eleanor and Knight Islands, southwest of Bligh Reef where the Exxon tanker grounded, causing the nation's worst tanker spill.

The researchers dug 12 holes on each beach to a depth of 4 to 5 feet. The first summer, they used shovels. That didn't turn out well. Once they hit the lower, compacted layer of sediment, "we kind of broke our backs," Boufadel said. Sometimes, it took 16 hours to dig one hole, he recalled.

The second year, they switched to augers and jackhammers, he said.

Samples shipped for analysis

The researchers shipped the sediment, water and other samples back to Temple for analysis.

The study is part of a recent spate of studies funded by the spill council on the lingering effects of oil in Prince William Sound. The spill council is the agency in charge of spending the $900 million in Exxon Valdez spill restoration funds.

Based on its own studies, Exxon contends that the oil that remains in beach sediment isn't hurting the environment.

Boufadel's findings aren't surprising, and they don't demonstrate a need for fur-

see PERSISTENCE page 17

Petroleum news

Oil Patch Bits

Alaska Railroad schedules open house in Fairbanks


ALASKA RAILROAD

The Alaska Railroad said Jan. 19 that it invites the public to an open house 4-6:30 p.m., Tuesday, Jan. 26 at the Alaska Railroad Depot, 1745 Johansen Expressway in Fairbanks. The venue provides an opportunity to review and comment on a proposed Program of Projects for 2010. The open house will showcase continuing and proposed capital improvement projects that are in various stages, from conceptual planning, to engineering and construction. Project managers will be on-hand to explain projects that are located all along the railroad system from Seward to Fairbanks. An open house will also be held in Seward from 10a.m.-1:30 p.m., Friday, Feb. 19 at the Breeze Inn, 303 N. Harbor St. Open houses were held in Anchorage Jan. 20 and in Wasilla Jan. 21. For more information visit www.alaskarailroad.com.

Lynden Air Cargo assisting with the Haiti relief

Lynden Air Cargo said Jan. 15 that it is using the oversized capacity of its L 100-30 Hercules aircraft to fly rescue vehicles, portable kitchens and other relief supplies to Port-au-Prince, Haiti, after a Jan. 12 earthquake devastated the capital city. Within hours, Lynden Air Cargo pilots were flying relief missions out of Washington, D.C., and they continue to pick up more supplies from U.S. points to deliver in support of humanitarian rescue efforts. "With an urgent need for relief supplies, aid flights are critical to prevent more human suffering. We are coordinating flights as quickly as possible in cooperation with government authorities," said Judy McKenzie, Lynden Air Cargo president. Lynden operates a fleet of six Hercules around the world; the unique features of the aircraft make it ideal for flying aid into isolated disaster areas. For more information visit www.lynden.com.

NAC lands in Haiti in support of relief efforts

Northern Air Cargo said Jan. 18 that one of its Boeing 737 aircraft landed in Port-au-Prince, Haiti, in support of earthquake relief efforts in the region. The company anticipates flying many more flights in the coming weeks. NAC has had one of its aircraft based in Texas flying domestic and international charters since December, so it was available to respond quickly. "We are well aware of the gravity of the situation in Haiti, and we are glad we had an aircraft available to help," said company spokeswoman Margot Wiegele. "We have the capacity to stay in the region for the next several weeks if the need exists." For more information visit www.northernaircargo.com

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

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FINANCE & ECONOMY

Prudhoe trust collects $29.5M from BPXA

The BP Prudhoe Bay Royalty Trust has collected nearly $29.5 million from BP Exploration (Alaska) Inc. to settle claims stemming from the 2006 pipeline spills in the Prudhoe Bay oil field on Alaska's North Slope.

The royalty trust, which is publicly traded on the New York Stock Exchange, reported it had received the funds from an escrow account on Dec. 24. The trust and BPXA had reached a settlement agreement on May 8, 2009.

The settlement resolves issues related to the temporary shutdown of Prudhoe following oil spills in March and August of 2006, possibly reducing royalty payments to the trust in 2006, 2007 and 2008, a trust press release said.

The settlement does not release BPXA from claims for reduced royalty payments in 2009 or any subsequent year, the trust said.

Created in 1989, the BP Prudhoe Bay Royalty Trust holds an overriding royalty interest that entitles the trust to a royalty on 16.4 percent of the first 90,000 barrels of the average daily net production of crude oil and condensate per quarter from BPXA's working interest in the field.

The Bank of New York Mellon acts as trustee for the royalty trust.

Leaks caused shut-ins

The corrosion-related leaks from major Prudhoe sales lines partially shut down the nation's largest oil field and led to subsequent field disruption as BPXA tested and replaced pipes.

Ultimately, BPXA pled guilty to a federal pollution misdemeanor amid accusations from prosecutors, pipeline regulators and members of Congress that BP was negligent in its maintenance of the pipes.

The royalty trust wasn't alone in pursuing financial claims against BPXA.

The State of Alaska is pressing a civil lawsuit in Alaska Superior Court seeking potentially $1 billion or more in lost revenue to the state treasury and the Alaska Permanent Fund as a result of the leaks and ensuing production shut-ins.

BPXA operates Prudhoe on behalf of itself and other owners ConocoPhillips, ExxonMobil and Chevron.

—WESLEY LOY

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PERSISTENCE

ther cleanup, says Exxon contractor Paul Boehm.

"Scientists who have studied spills for years know that after crude oil spills you can and will find buried oil many years later, but that it does no harm and does not need to be (removed)," said Boehm, a chemist and vice president for Exponent, an international consulting firm that works for Exxon on spill-related issues.

The spill council disagrees. Its own research concludes that the sound's otters and sea birds are still ingesting harmful amounts of residual oil when they forage for food.

"Further monitoring will be needed to determine whether the environment is truly on a trend to complete recovery," according to a recent spill council report.

The spill council has been getting regular updates on Boufadel's work, said Peter Hagen, a National Marine Fisheries Service scientist who is managing some of the council's lingering-oil studies, including Boufadel's.

Hagen said the council has discussed the possibility of funding pilot projects to determine the best ways to remove residual oil from the beaches.

For example, it might be possible to degrade the oil by injecting oxygen or nutrients into wells or trenches dug into the beaches, according to a recent council report.

Those methods might be preferable to digging the oil out, scientists say.

"I don't think anyone wants to rip up the beaches again," said Jacqueline Michel, a South Carolina scientist who is finalizing a council-funded study that will map where the residual oil lies and identify which places have the greatest amount.

In its recent report, the council said it can identify 50 beach segments — a total length of about 1.6 miles — where a significant amount of oil remains buried.

When state and federal prosecutors presented their plan for additional oil cleanup on shorelines to Exxon in 2006, they estimated it would cost $92 million over several years. ●

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LIEPERT

that was once the envy of oil and gas jurisdictions across North America.

Calgary energy analyst Peter Linder said the decision to demote Mel Knight from the energy post is a "smart" move at a time when the government is "about to announce a new fiscal regime … that should be much more industry friendly, yet still gives a fair share to the people of Alberta."

He said the government's attempt to impose a 20 percent royalty hike was clear evidence that Knight has failed to heed industry warnings.

Now the Conservative government (with 68 of 83 seats in the provincial legislature) has made a breathtaking dive in opinion polls to a record low of 25 percent, compared with 39 percent for the fledgling Wildrose Alliance (which holds three seats, two of them from recent defections by government legislators).

Stumble out of gates?

But Liepert may have made the slightest stumble coming out of the gates.

He told the Globe and Mail the Alberta cabinet must decide how to "change our policy of come-one, come-all" before economic recovery brings the oil sands back to life.

Liepert said the current lull in construction gives the government time to decide if and how it can schedule new projects.

To those in the industry who believe the government has no role to play in the development of its oil and gas resources, Liepert said: "That's not going to happen."

Within a matter of hours he was clarifying that position.

Instead of conveying any suggestion of government intervention, Liepert said he was merely making a case to "talk about and think about (what might happen) two or three years down the road when development picks up again. I don't think we're offside with the industry," he told the Edmonton Journal.

Stelmach was even more emphatic, saying the government's objective is just to ensure the infrastructure is in place to match the pace of business development.

Liepert has made it clear he is anxious to bring the government and the industry back to the same page on royalties.

Prodded by Stelmach's insistence that the two sides must be partners in attracting new investment to unconventional gas development, Liepert said his first priority will be to act on the findings, expected to reach the cabinet late in January, of a review comparing Alberta's royalties and fiscal framework with other North American oil and gas jurisdictions.

He said it is vital to restore a dialogue that industry leaders say has been missing from the three-year process of introducing a new royalty framework.

Applying common numbers

Without conceding that the royalty increases imposed a year ago were a mistake, Liepert committed the government to working more closely with the industry and applying common numbers in developing royalties.

"What we need to do is make sure government is not a hurdle to future investment," he said.

Stelmach said an improved dialogue is essential as Alberta deals with "significant structural changes" in the gas sector and shifts its focus to shale gas.

"We own the resource, but the industry puts up the critical dollars, which are at risk unless we have a very good competitive position as a province," he told a conference call.

A spokesman for the Canadian Association of Petroleum Producers and Roger Soucy, president of the Petroleum Services Association of Canada, said there is a strong sense of concern within the industry over how the government will handle the competitiveness review.

Soucy said Liepert does "have a general understanding of industry issues," but his performance will be judged by how he handles the competitiveness review.

Gary Leach, executive director of the Small Explorers and Producers Association of Canada, said in a statement that a strong economic policy is vital to guide Alberta's energy strategy and accelerate the province's economic recovery.

"The first step to achieving this goal is for government and industry to work together," he said. ●

Contact Gary Park through publisher@petroleumnews.com

Second energy minister shown the door

These are dangerous times for Canada's energy ministers.

In less than a week, those holding the portfolio in Alberta and now the Canadian government have been moved down the pecking order.

Mel Knight handed the reins of control in Alberta to Ron Liepert, and Lisa Raitt, after only 15 months as Canada's Natural Resources Minister, has been yanked from the job by Prime Minister Stephen Harper in favor of Christian Paradis, a 36-year-old star-in-the-making.

Despite giving his home province of Quebec some added clout in the federal cabinet, Paradis may face his toughest job selling the importance of hydrocarbons in Quebec, which has adopted California's low-carbon fuel standard and is the bastion of strongest Canadian opposition to the oil sands.

Gilles Duceppe, leader of the separatist Bloc Quebecois, reflected the mood when he said Paradis was "stooping very low to accept a portfolio like that. A Quebecer will be defending the indefensible. That's shameful."

It matters little in Quebec that the energy sector is responsible for 25 percent of Canada's Gross Domestic Product, or that Alberta's energy wealth is redistributed to economically weaker regions such as Quebec.

It is not clear whether Paradis will attempt to present a more complete picture of the oil sands in Quebec or across Canada.

But many observers note that the real control at the federal level over the petroleum industry is in the hands of Environment Minister Jim Prentice, who runs Canada's climate-change agenda, has government oversight of the Mackenzie Gas Project and, like Harper, comes from Calgary, the headquarters of the Canadian industry.

Even so, Paradis can't be shoved out of the MGP picture, given the importance of current attempts to negotiate a fiscal regime with the project partners and the cabinet's ultimate role, once the regulatory agencies have completed their work this year, in issuing final approval.

The change was forced on Harper by a series of gaffes committed last year by Raitt, who is facing an investigation by the federal ethics commissioner into allegations of improper fundraising activity and who left confidential government documents in a TV studio.

—GARY PARK

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GREENING OF OIL

understand the oil industry write about its environmental impact'; the last is an exact quote from a strong environmentalist, although there were others like it," she said.

"I think he was hoping Greening would act as an industry watchdog. But we purposefully stayed away from the word 'watchdog' because of its negative implications. We're not taking a position, although Greening of Oil does communicate what we have observed covering Alaska's oil and gas industry, and that is the gradual reduction of its environmental impact."

"But, as Greening's Editor-in-Chief Allen Baker says, we will 'stick to the facts and let the science speak for itself,'" Cashman said.

To read what Mother Nature Network, the Houston Chronicle and others have said about Greening of Oil, visit the Buzz page at www.greeningofoil.com.

—PETROLEUM NEWS

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APACHE

for Apache and the Kitimat LNG project will continue to foster our growth in that area,” he said.

Stage set for gas surplus

Wall said development of Horn River and other Canadian gas along with the Marcellus shale play in Pennsylvania sets the stage for a gas surplus in North America.

“I do think it could benefit other markets by being able to export some of that surplus gas,” he said.

“With the excess gas here in Canada you are not captive to the United States. You are actually opened up to new markets around the world.”

Alfred Sorenson, chief executive of ficer of Galveston LNG, the parent company of Kitimat LNG, said the economic fundamentals “remain strong for exporting natural gas from Western Canada to international markets where natural gas is in demand, such as Asia.

“As natural gas supply and reserves continue to increase in North America, Kitimat LNG’s terminal will provide producers in Canada with secure access to key worldwide markets.

Irene Schmaltz, Kitimat LNG’s vice president of supply marketing, told a gas conference last November that the export terminal will enable producers to “include LNG in their portfolios. It will help stimulate the development of gas reserves in Canada.”

“For end users, it’s a new source of supply for them. They like that. They want to diversify their supply source and, from a political point of view, they consider Canada very low risk.”

Kitimat LNG President Rosemary Boulton said Apache brings a “great presence” to the project’s supply equation and provides an opportunity “for us to bring additional partners, on either capacity or equity, into the plant,” which is estimated to cost C$3 billion and come onstream in 2014.

EOG Resources has also signed a memorandum of understanding to contribute 100 million to 200 million cubic feet per day of Horn River gas to Kitimat, but has yet to comment on the change of ownership.

Not all sold on LNG

But not all of Canada’s gas players are sold on the notion of LNG exports from Canada.

Russ Girling, chief operating officer of TransCanada, said a producer shipping gas to the British Columbia coast would need a netback higher than C$9.25 per thousand cubic feet, assuming a wellhead price of C$5.25, C$1 for pipeline transportation to the Kitimat port and C$3 for liquefaction.

In contrast, a shipper seeking access to the Alberta gas hub would pay only a 25-cents-per-gigajoule receipt charge for a minimum three years and the Canadian mainline toll to the Eastern Zone would add only C$1.60 per gigajoule.

TransCanada Chief Executive Officer Hal Kvisle said LNG proponents are targeting gas prices of $15 per million British thermal units from Asian buyers.

“If I was a Japanese utility buyer I would be asking why I should pay that price,” he said. “The world has changed. There’s now lots of LNG out there. Let’s see what the price of LNG is rather than tying it to oil.”

It’s not yet clear whether Kitimat LNG will affect projections for LNG imports to the Pacific Northwest region (Idaho, Oregon, Washington and British Columbia), which the Northwest Gas Association forecast in a 2010 outlook will see grow by 1 percent a year over the next decade, driven by demand for gas-fired electrical generation and continue growth in residential demand.

“Dozens of new import terminals have been proposed across North America, including three in Oregon,” the NWGA report said. “North American supply developments notwithstanding, LNG will serve a key role in the continental and regional energy picture over the long term.”

The NWGA predicted that LNG imports to the United States will double in the next five years to 1 trillion cubic feet.

In addition to LNG, the NWGA listed four overland pipeline projects that have been proposed to serve the Pacific Northwest drawing on new production from the U.S. Rockies and northeastern British Columbia. ●

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FARM-IN

of $463,795.20 for the 2,560-acre tract, ADL 390680, in the state’s 2004 North Slope areawide oil and gas lease sale. Eni acquired the lease from Armstrong in the summer of 2005 when it bought Armstrong Alaska’s assets on the North Slope. The lease has a fixed royalty rate of 16.67 percent and expires in 2012.

Winegarner said ADL 390680 is one mile west of the western Kuparuk River unit boundary.

It is north of the Kuparuk Tarn development, discovered in 1991 by ARCO Alaska at its Bermuda No. 1 well in 1991.

Multiyear program possible

BRPC told the state that North Tarn exploration operations are expected to begin in February with completion at the end of the winter tundra travel season.

The program includes a 4-mile ice road from existing Kuparuk River unit gravel roads to the North Tarn ice pad location.

An ice drill pad will be constructed at the North Tarn site and work may include a short-term production flow test. “If significant hydrocarbons are found during drilling, the well may be tested to confirm flow rates and reservoir characteristics,” the company told the state.

The drill pad will be no larger than 500 feet by 500 feet with facility layouts similar to previous BRPC exploration programs at the Sak River prospect.

The company said a comprehensive evaluation of the surface use area was completed in August 2009 and the proposed ice road route and pad location were surveyed by foot, helicopter and aerial photography to determine cultural resources present in the area and to select rig transport suitability.

BRPC said the ice pad site was selected to minimize the number of exploration or appraisal wells needed prior to development.

A modular camp, supplied with the drilling rig, houses some 60 people and will be used to support exploration activities.

The proposed schedule shows 14 days of pre-pack ice road alignment beginning in February and 30 days of ice road construction in February and March. Mobilization of the camp and drill rig is estimated to take 10 days in March with 45 days in March and April scheduled for drilling, followed by 10 days to demobilize the camp and rig in April and May.

Beechey Point unit

BRPC is the operator for a multiyear program near infrastructure on the central North Slope, and that program is its focus this winter.

The company drilled the North Shore No. 1 and Sak River No. 1 wells in the Gwydyr Bay area north of the Prudhoe Bay unit in 2006-07. It sidetracked and tested the North Shore at more than 2,000 barrels per day the following year.

Alaska’s Division of Oil and Gas approved the formation of the Beechey Point unit at North Shore in August. BRPC has said it wants to fast track development at the find, perhaps using trucks to transfer North Shore oil to a tie-in with the Kuparuk pipeline. The company told the state that development of several small oil accumulations in the area is a possibility.

BRPC received drilling permits in late December from the Alaska Oil and Gas Conservation Commission for two sidetracks from the Sak River well, Sak River 1A and Sak River 1B.

Winegarner said BRPC is Alaska’s most active oil explorer.

“The current tax credit system in Alaska is sustaining our current level of exploration,” he said. “However, increasing exploration tax credits and/or allowing explorers to cash earned credits sooner would allow the BRPC Group to conduct a higher level of exploration activity in Alaska in future winters.” ●

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BP EXPLORATION (ALASKA) INC.

The pipe arriving at the Port of Anchorage comes from Sumitomo Metals, a major pipe manufacturer in Japan.

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PIPE COSTS

the energy industry term OCTG — oil country tubular goods.

That such ships come direct to Anchorage is something new, the result of a lot of collaboration among BP procurement managers, the Anchorage port, Japanese pipe maker Sumitomo Metals and its subsidiaries in Alaska.

The direct imports are helping save time and money as BP prepares to drill ultraextended-reach wells to tap its Liberty offshore oil deposit, and continues development drilling in Prudhoe Bay and other North Slope fields.

Roundabout journey

Usually, pipe for BP's operations in Alaska takes a circuitous route to get here.

Pipe from a variety of steel mills generally goes first to Houston, or sometimes Washington state.

From Houston, the pipe proceeds by railroad to the Seattle area, where the rail cars are loaded onto barges bound for the Alaska port of Whittier.

From there, the Alaska Railroad delivers the pipe to either Anchorage or Fairbanks, with trucks hauling it up the rugged Dalton Highway to feed drilling rigs on the Slope.

The full journey can take several weeks.

Sautel and Bob Talbott, BP Alaska's chief procurement officer, began to think about a better way. It was in keeping with BP's recent efforts to work with suppliers and contractors on controlling costs and doing things more efficiently.

Liberty presented the opportunity to import pipe directly to Anchorage, Talbott told Petroleum News in a recent interview.

That's because of the volume of pipe Liberty will require for its extreme horizontal wells, some of which are expected to reach up to eight miles out to pierce a reservoir with an estimated 100 million barrels of recoverable oil. A powerful Parker rig already is on site, with drilling expected to start this spring.

Liberty demands big enough loads of tubing and casing to justify cargo ships making stops in Anchorage, Talbott said.

Three ships have arrived so far: one in August, one in December and one in early January.

Alaska connections

The pipe arriving at the Port of Anchorage comes from Sumitomo Metals, a major pipe manufacturer in Japan.

Sumitomo Metals, with head offices in Osaka and Tokyo, has a long-term supply contract for pipes with London-based BP.

Sumitomo Corp. of America in 2003 won a contract to provide tubular goods and logistical services to BP in Alaska, which led to the founding of a local Sumitomo subsidiary called Tubular Solutions Alaska.

Tubular Solutions coordinates BP's pipe stock, managing the oil company's pipe yard in Fairbanks, Talbott said.

Another local Sumitomo company, Unique Machine, also is an integral piece of BP's OCTG pipeline.

Based in Anchorage, Unique Machine bills itself as "Alaska's largest machine shop." It provides critical services such as threading, and has the capability to work with the large-diameter pipe required for Liberty, Talbott said.

The pipe arriving at the Port of Anchorage can be big stuff, up to 17 inches.

To receive the pipe, a lot of logistical arrangements had to be hammered out, Sautel said.

North Star Terminal & Stevedore Co. workers unload the pipe from the ships, and Sourdough Express trucks it away.

Stuart Greydanus, director of operators for the Port of Anchorage, said the port has ample room to accommodate the pipe in its laydown yards.

Cranes lift the pipe out of the ship and set it on the ground. Forklifts then stack the tubing on a chassis for hauling, Greydanus said.

Working out the details was easy, he said: "A few meetings."

Having the pipe shipped directly to Anchorage is a welcome development for the city's growing port.

"Absolutely, it's good for the port," Greydanus said. "It's added dockage revenue and it's added wharfage revenue."

More imports likely

Typically, it takes about 45 days to move pipe from Houston to a drilling rig in Alaska, a Sumitomo Corp. of America Web site says.

That's a long, expensive journey, one Sautel and Talbott are aiming to reduce with the direct pipe imports to Anchorage.

But the Japanese mill can't supply all the pipe BP needs, so direct imports aren't a comprehensive solution, Talbott said.

"It's another tool in the toolbox," he said. "We're going to pick our spots and use it where we can."

Besides saving distance, time and cost, Talbott noted the direct imports have one other benefit — safety.

"The less handling we have to do with this pipe, the less opportunity for something unfortunate to happen," he said. ●

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LEGISLATURE

considerable time working on PPT and ACES and consultants working for the Legislature did extensive modeling for the committee on projected results from different tax proposals.

Stedman said from his perspective what doesn't work in ACES is "our gas tax component and the way it's calculated," because the gas part of the tax package was based on the 2006 assumption that the state would take 20 percent of its gas in kind and own 20 percent of the gas pipeline deal proposed under the Stranded Gas Development Act.

He said the state lacks the information it needs to fix the gas portion of the tax.

"We cannot, in my opinion, set the gas tax because we do not know the cost of the line and the information's not available."

House Democrats were wary of a tax change.

Rep. Mike Doogan of Anchorage, said Jan. 20 at a House minority press availability that "generally we want to know what we get for what we're being asked to give," if a tax reduction is on the table. He said he thinks everyone understands that it's in the interest of the oil industry "to claw back as much money as they can. … That's what they're in the business for." Doogan said he would have to see "that there was actually some benefit to Alaskans and Alaska for making these changes."

Fairbanks Rep. David Guttenberg said that under ELF some fields were classified as marginal fields and paid very little in tax. "What economic development did they do when … it was basically not taxed at all?" he asked, referring to concerns that tax rates under ACES make Alaska projects uncompetitive. ●

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