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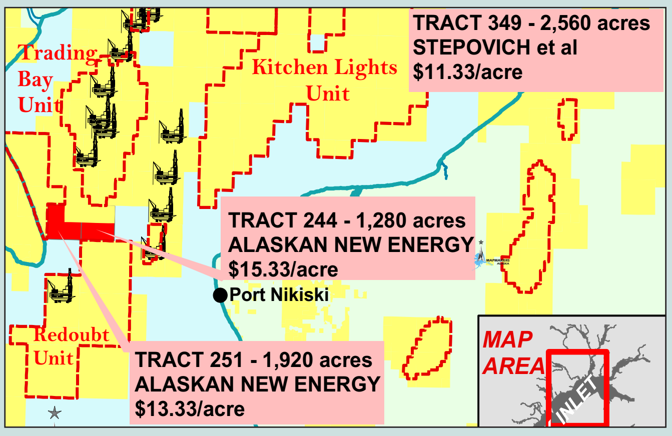
page 7 GVEA reconsiders approach to Healy plant as Homer Electric backs out



Cook Inlet sale draws bids on 4 tracts; no takers for Peninsula

The Alaska Division of Oil and Gas had no bidders at its Alaska Peninsula areawide oil and gas lease sale, held May 20 in Anchorage.

It did receive five bids on four tracts, 7,685 acres total, in the Cook Inlet areawide sale, with $110,009.65 in apparent high bids.

The state held its first areawide Alaska Peninsula sale in 2005 and received $1.1 million for 37 tracts. The next sale, in 2007, had one bidder and saw the sale of one tract. As with this year's sale, there were no Alaska Peninsula bidders in the 2008 sale.

This year's Cook Inlet turnout was the smallest since the state began offering the acreage in annual areawide sales in 1999.

The peak year for Cook Inlet areawide sales was 2006, when the state received $2.86 million in high bonus bids and sold 71 tracts.

Last year's Cook Inlet areawide sale drew more than half a million dollars in high bonus bids, with 18 tracts sold.

$1,527 per acre

William C. Kilpatrick had the highest per-acre bid at the sale, $1,527.05 an acre, a total bid of $7,635.25 for five-acre tract 597 which is surrounded by Ivan River unit acreage. According to state records Kilpatrick currently holds no oil and gas lease acreage.

The minimum required bid at the Cook Inlet sale was $10 an acre except for tract 597, for which the minimum bid was $1,000 an acre.

Jonne Slemons, division section chief for oil and gas leasing, said at the bid reading that Ivan River unit operator Chevron has filed an application to exclude tract 597 from an Ivan River participating area, but the application is not yet complete.

Alaskan New Energy LLC took two tracts, bidding $15.33 an acre for tract 244 and $13.33 an acre for tract 251, adjacent tracts off West Forelands in waters south of the Trading Bay unit, a total of $73,369.30.

Alaskan New Energy has no current state acreage position.

A bidding partnership of 50 percent Nick Stepovich, 25 percent Daniel R. Gilbertson and 25 percent Alaska LLC, took tract 349, bidding $11.33 an acre, a total bid of $29,004.80, for the acreage south of the Kitchen Lights unit in mid-Cook Inlet.

see **LEASE SALE** page 16

EXPLORATION & PRODUCTION

Where to from here?

Will the western Cook Inlet oil fields recover from Redoubt eruption?

BY ALAN BAILEY
Petroleum News

While Redoubt Volcano on the west side of Alaska's Cook Inlet continues to rumble, threatening another massive explosion that would hurl ash into the sky and floodwaters down the Drift River on the volcano's northern flank, the neighboring Drift River oil terminal and 10 Chevron-operated offshore oil platforms that depend on the terminal for exporting their products remain silent, shut-in since early April when eruption-induced floodwaters flung mud against the terminal's protective dike and across the facility's airstrip.

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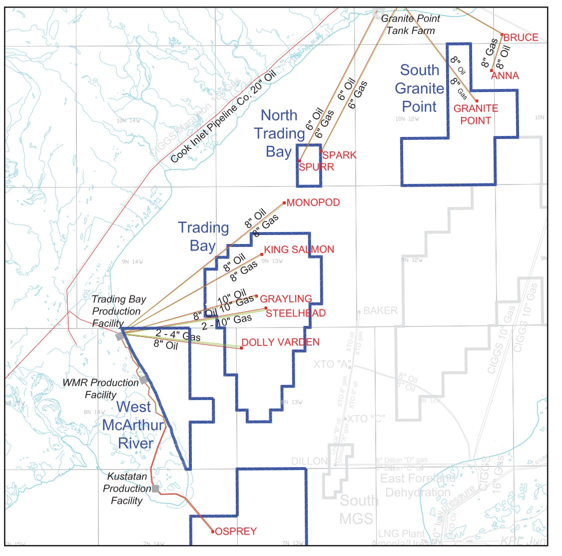

EXPLORATION & PRODUCTION

Rallying to oil sands

French, Norwegian firms make a case for expanding their presence in Alberta

By GARY PARK
For Petroleum News

From big and small, from domestic and international stages, there is a steady, rebuilding drumbeat of support for the Canadian oil sands, motivated largely by a belief that cheap oil is disappearing.

The International Energy Agency said production from large existing fields around the worlds is shrinking by about 7 percent a year, while the rate of decline is happening even faster.

France's Total, admittedly a minority voice among majors, is predicting that global output will "plateau" at 95 million barrels per day after 2020, only 10 mil-

see **RALLY** page 14

From the fringe to the center

A landmark study by energy consultant IHS Cambridge Energy Research Associates forecasts the Canadian oil sands could account for 37 percent of United States oil imports by 2035, compared with 19 percent today, IF…

If the current economic recession is not too long or deep.

And if the pace of technological change

see **STUDY** page 14

EXPLORATION & PRODUCTION

Nikaitchuq oil in 2010

Missed sealift last year led to delays; company expects modules next year

By ERIC LIDJI
Petroleum News

Eni US Operating Co. Inc. expects to start producing oil from an offshore North Slope unit in December 2010, according to new information from the Alaska Division of Oil and Gas.

Earlier this year the local subsidiary of Italian oil major Eni delayed development work at the Nikaitchuq unit, citing the fall in world oil prices and the weak economy. The company originally planned to start producing oil from the unit by the end of 2009, but a top state oil official said Eni would instead delay development by six months to a year.

In mid-March, Eni asked the state for more time to develop Nikaitchuq. The state approved that request on May 13, extending the terms of the unit agreement by almost two additional years, to April 1, 2011, from the current expiration date of April 30, 2009.

In its decision, the state said Eni decided to delay development not only because of the weakened economy and the drop in oil prices — which fell from a high of nearly $150 a barrel last summer to current levels around $50 a barrel — but also because the company missed the window to barge "processing and operations modules" to the North Slope.

Eni was building those facilities in Louisiana, not Alaska, and according to the state, Hurricane Ike caused a "work stoppage" at the Louisiana fabrication yard where the construction was taking place last September. Because of the seasonal restrictions, companies have a brief window each summer to sealift

see **NIKAITCHUQ** page 13

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Petroleum News | *A weekly oil & gas newspaper based in Anchorage, Alaska*

● LAND & LEASING

Pioneer drops nearly 150,000 acres

Move represents shift from exploration to development, lower prices; 51 leases split between Beaufort Sea and south of Prudhoe; company says focus now on Oooguruk development drilling

By ERIC LIDJI
Petroleum News

Pioneer Natural Resources relinquished 51 leases in April, according to state records.

The leases cover 145,448 acres spread across two areas. The company gave up seven leases in the waters of Stefansson Sound, north of Prudhoe Bay, and 44 leases in the central North Slope, south of Prudhoe. The relinquishments went into effect on April 30.

The relinquishment represents both a shift of focus from exploration work to development work for Pioneer in Alaska, and an eye on keeping costs down in a lower price environment, Pioneer spokesman Tadd Owens told Petroleum News May 20.

"Successfully executing our development drilling plan at Oooguruk is the number one priority for the Alaska division," Owens wrote in an e-mail. "With so much of our human and capital resources devoted to our operating areas it was unlikely we would be engaged in any activities on our exploration acreage over the next few years."

Pioneer arrived in Alaska as an explorer, but within a few years transitioned into being a developer on the North Slope. After a string of unsuccessful exploration wells, the company indefinitely discontinued its exploration activities in Alaska in late 2007.

The company brought the Oooguruk unit online last summer.

Other acreage dropped, sold

Along with partners ConocoPhillips and Anadarko, Pioneer gave up 300,000 acres in the National Petroleum Reserve-Alaska in September 2007. Last summer, Pioneer sold three leases in Gwydyr Bay to a joint venture led by Brooks Range Petroleum Corp.

The newly relinquished leases south of Prudhoe Bay include Hailstorm No. 1, the well Pioneer drilled in the NE Storm unit with ConocoPhillips in the winter of 2005 and 2006.

The leases also include the Hemi State 03-09-11 well drilled by Mobil in 1969, the Hemi Springs Unit No. 3 well drilled by ARCO Alaska in 1985, the Toolik No. 2 well drilled by ARCO Alaska in 1969 and the Sequoia No. 1 drilled by Conoco in 1992.

Pioneer is at least the third company to give up state or federal leases in the Beaufort Sea this year, following Shell and ConocoPhillips. Pioneer never drilled on its Beaufort leases, although the holdings sat near the Midway Islands, where Standard Oil of Ohio drilled Reindeer Island No. C-1 in 1969 and Reindeer Island Strat Test No. 1 in 1979. ●

● FINANCE & ECONOMY

BP plans spending cuts, but not a lot

BP planning for $50 oil; Pioneer focused on Alaska developments during low price environment; Shell planning new anchor handler, companies tell annual Alaska Oil and Gas Association meet

By ERIC LIDJI
Petroleum News

BP isn't planning any major cuts this year in response to lower oil prices.

"We're probably not going to spend next year as much as we thought, but it's not a major change. We're going to be okay. We're still investing a lot of money," John Minge, the new head of BP Exploration (Alaska) Inc., said during the Alaska Oil and Gas Association annual luncheon on May 13.

Last November, BP announced a $1.2 billion capital program for Alaska in 2009, a 33 percent increase from 2008 spending. BP planned to direct one-third of its spending on the offshore Liberty project, the Denali gas pipeline and heavy oil extraction technology.

But BP also said it planned to defer development work in the Western Region of Prudhoe Bay, and said it expected a 10 percent drop in total Prudhoe Bay drilling year over year.

Minge said BP would need to cut costs to adjust to current prices. "At $40 to $50 a barrel, our base business — the current production — is not a sustainable business," Minge said, adding that costs have more than doubled since oil prices last hit $50 a barrel in 2005.

Acknowledging that cutting costs at BP means cutting revenue for service companies, Minge said the company has met with 150 of its contractors to talk about costs.

"We're in discussions; we're working together, and things are going to be okay," he said.

Pioneer to frac at Oooguruk

Pioneer Natural Resources plans to spend between $87.5 million and $105 million in Alaska this year, said Ken Sheffield, the head of Pioneer in Alaska.

Pioneer plans to spend between $250 million and $300 million companywide this year, with around 35 percent of that spending directed toward two projects in Alaska.

> *"At $40 to $50 a barrel, our base business — the current production — is not a sustainable business."*
> **—John Minge, president, BP Exploration (Alaska) Inc.**

Sheffield said that in response to falling oil prices last year, Pioneer cut the number of drilling rigs it had in operation from 29 to one. The remaining rig is doing development drilling at the Oooguruk unit on the North Shore, which the company brought online last summer.

Sheffield said Pioneer decided to continue at Oooguruk because the project is logistically challenging and the company didn't want to lose momentum. He also said Pioneer is currently focusing on oil plays like Oooguruk because it sees a price advantage over gas.

Pioneer began development drilling at Oooguruk more than a year ago. Sheffield said the company had "good results" from its initial wells into the Kuparuk pool. The company is currently "batch drilling horizontal laterals" into the deeper Nuiqsut reservoir at the unit.

"We're preparing for fracture stimulation this summer," Sheffield said.

He said Pioneer is looking to expand work at Oooguruk, and the company would "likely make some investments" at the Cosmopolitan unit on the Kenai Peninsula in 2010.

Shell to build anchor handler

Shell shot 1,000 miles of 3-D seismic in the Chukchi and Beaufort seas in Alaska in 2008.

Rick Fox, Shell's Alaska asset manager, said the company spent $50 million on baseline science, adding to investments made by the U.S. Minerals Management Service and other groups.

Fox said the company is "making a long-term lease with a U.S. company to build an anchor handler" by 2012. The ice-class vessel will cost around $150 million to build. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

● NATURAL GAS

Consortium locates gas hydrates in GOM

Government and industry project finds saturated deposits in reservoir sands at two out of three sites drilled in offshore expedition

By ALAN BAILEY

Petroleum News

In another key step towards the possible future development of gas hydrates, a potential major source of natural gas, a research team has found highly saturated deposits of the material in reservoir-quality sands under the Gulf of Mexico, the U.S. Department of Energy announced May 14. During a 21-day expedition using the semi-submersible rig Helix Q4000 the team drilled through gas hydrates in a variety of different rock types and located resource quality hydrates in two out of three reservoir sand locations that the team had targeted.

"Prior to this expedition there was little documentation that gas hydrate occurred in resource-quality accumulations in the marine environment," DOE said.

The DOE National Energy Technology Laboratory is collaborating in this joint industry project with entities including the U.S. Geological Survey, the U.S. Minerals Management Service and an industry research consortium led by Chevron, DOE said.

Gas hydrate (or more correctly methane hydrate) contains methane molecules, the primary component of natural gas, trapped in a lattice of water molecules to form a white, rime ice-like solid that is stable in relatively low temperatures and elevated pressures, such as exist in some submarine settings or perhaps a couple of thousand feet under Arctic tundra. When decomposed by altering the pressure or temperature, the solid hydrates release about 164 times their original volume in natural gas.

Initial phase

In 2005, in an initial phase of the Gulf of Mexico investigation, the joint industry project conducted a drilling and coring program that tested possible drilling hazards relating to the presence of gas hydrates in clay-dominated material immediately under the seafloor.

A major focus of subsequent work has been the refinement of techniques for locating gas hydrate deposits in the subsurface. In 2006 the project team began investigating numerous possible gas hydrate locations using detailed geologic interpretations, coupled with sophisticated techniques for analyzing 3-D seismic data, to delineate and prioritize drilling sites.

That led to this year's drilling project, a project using state-of-the-art logging-while-drilling tools that enable downhole logs to be run while drilling is in progress, thus enabling the hydrates to be detected in the subsurface rocks, while also leading to three-dimensional images of the hydrate-bearing sediments. And the drilling results confirmed the effectiveness of the techniques used to determine the drilling locations.

"During the expedition, gas hydrate was found at saturations ranging from 50 percent to more than 90 percent in high-quality sands," DOE said. "The deposits were also found in close accordance with the project's pre-drill predictions, providing increased confidence in the gas hydrate exploration and appraisal technologies."

Potential development

The drilling in the Gulf of Mexico represents a move towards the possible development of submarine gas hydrates that are thought likely to be more technically challenging to produce than Arctic land-based hydrates, such as those near the existing oil and gas infrastructure on the North Slope.

In fact DOE has been working with several teams in northern Alaska, investigating ways of locating gas hydrate deposits on land and evaluating the eventual possibility of gas hydrate production, a possibility rendered appealing by estimates of vast volumes of methane locked up in the hydrates and the emerging popularity of natural gas as a clean-burning fuel.

In 2007 BP in collaboration with DOE successfully drilled a gas hydrate stratigraphic test well at Mount Elbert on Alaska's central North Slope, recovering about 100 feet of hydrate bearing core and leading to plans for a gas hydrate production test. DOE is also working with ConocoPhillips on the North Slope to test the use of carbon dioxide to displace methane from the hydrates, a technique that would serve the dual purpose of producing natural gas and sequestering unwanted carbon dioxide.

And at the western end of the North Slope, DOE is working with the North Slope Borough and Petrotechnical Resources of Alaska to drill an initial well to test for possible gas hydrates in a gas field near Barrow.

Greater understanding

The various gas hydrate projects are enabling researchers to edge towards a greater understanding of what might be involved in commercial gas hydrate exploitation. And, on the basis of gas hydrate production modeling combined with successful tests in the Mount Elbert well and in another gas hydrate well, the Mallik well in the Mackenzie Delta, USGS has determined that sustained recovery of natural gas from gas hydrates is technically feasible — in October the agency published a technically recoverable hydrate resource estimate for Alaska's North Slope.

However, a determination of whether gas hydrate production will prove economically viable remains some distance in the future. ●

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SAFETY & ENVIRONMENT

Agency agrees to walrus review deadline

The U.S. Fish and Wildlife Service has agreed to make an initial determination within four months on whether the Pacific walrus merits additional protections under the Endangered Species Act.

A federal judge May 18 approved a settlement between the agency and the Center for Biological Diversity, which sued in December to force a decision.

The group filed a petition in February 2008 to list walrus because of the loss of their sea ice habitat due to global warming, and used the same justification to successfully petition for protection of polar bears.

Listing would require federal agencies to consult with the Fish and Wildlife Service to ensure that any action they authorize will not jeopardize walruses or adversely modify their critical habitat.

—THE ASSOCIATED PRESS

● NATURAL GAS

Chugach responds to contract challenges

Says Enstar and Beluga Pipe Line misunderstood the terms of a contract with Aurora to replace gas pulled during compressor trips

By ERIC LIDJI

Petroleum News

Chugach Electric Association responded on May 14 to challenges that its proposed "Replacement Gas Contract" with Aurora Gas doesn't sufficiently cover gas draws.

The proposed contract supplies Chugach with gas to replace volumes it takes from the Beluga Pipeline during a compressor trip. Under the contract, Aurora would supply Chugach with up to 700,000 cubic feet of gas within 24 hours of each incident.

Chugach takes gas from the Beluga Pipeline to avoid a system outage.

The contract is separate from a larger and longer-term contract with ConocoPhillips.

Beluga Pipe Line Co., which owns the line, said it needed gas taken from the pipeline to be replaced as it is being drawn in order to avoid a system outage of its own. Chugach said it has tried to lessen the impact of compressor trips with automation that limits the time and quantities of gas pulled from the line, and with the replacement contract.

The gas Chugach pulls comes from the Beluga Pipeline "line pack" or the gas inside the pipeline at any given time. The Beluga Pipeline, owned by Marathon, runs from the Cook Inlet Gas Gathering System, or CIGGS, at Granite Point, north to the Beluga River field.

On the Web

See previous Petroleum News coverage:

"Chugach looking at backup contract," in May 3, 2009, issue at www.petroleumnews.com/pnads/733521026.shtml

Companies question language

Beluga Pipe Line and Enstar said that while Chugach claimed in a letter to the RCA that the proposed contract obligates Aurora to provide gas, the language of the contract itself contains potential loopholes that could allow Aurora to get out of that obligation.

Chugach refuted this claim, saying the contract calls for up to 700,000 cubic feet for each event.

Enstar also said the proposed contract didn't make enough gas available, saying recent reports indicated Chugach needs between 34 million and 46 million cubic feet for a trip.

Chugach said Enstar was calculating rates, not actual volumes. "While the rates per day relied on by Enstar may appear high, these draws typically last no more than a few minutes and the rates themselves are not constant," Chugach said, citing three recent compressor trips that required the utility to pull between 55.5 mcf and 105 mcf of gas. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

● GOVERNMENT

Canada waging Arctic campaign

Defends sovereignty claims; Senate report urges more local control for 100,000 residents of Yukon, Northwest Territories, Nunavut

By GARY PARK

For Petroleum News

Canada is talking tough about defending its Arctic sovereignty claims, telling Russians and Europeans to back off, at the same time a Canadian Senate committee is cautioning the government to transfer more of its control over Canada's North to those who live in the region.

Coming right on the heels of a Russian government report that warns of possible military conflict over Arctic oil, Foreign Affairs Minister Lawrence Cannon said Canada's priority is to "work peacefully" with "our northern partners in the Arctic."

If that isn't possible, Canada is "an Arctic power and our government understands the potential of the North.

"Therefore, when and if necessary, this government will not hesitate to defend Canadian Arctic sovereignty and all of our interests in the Arctic," Cannon said.

A similar message is being spread across Europe, as the government of Prime Minister Stephen Harper wages a campaign to present Canada as an "Arctic power" and the owner of one-third of the Far North, including land and any oil, natural gas and minerals lying beneath the waters.

Cabinet ministers and ambassadors have been told to follow up on Cannon's statement to European leaders in Norway in April that "Canada is an Arctic nation and an Arctic power." That is being accompanied by the opening of a Canadian International Center for the Arctic Region in Oslo, a political institution designed to rebuff messages being sent by the European Union and Russia, and the unveiling of cultural banners and sculptures in London and Paris.

Cannon said the office will also play a research role, largely to "promote Canadian interests and influence key partners" on Arctic-sovereignty issues.

"Through our robust Arctic foreign policy, we are affirming our leadership, stewardship and ownership in the region," he said.

However, it's not all a bristling confrontation.

Meetings with Russia

There are reports that Canada's diplomats are again meeting with Russia, after a prolonged chill in relations, while the major issues are being aired by the Arctic Council, consisting of Canada, the United States, Iceland, Norway, Denmark, Sweden, Finland and Russia.

Cannon's bold stand occurs amid mixed and conflicting signals from the Russians, which have ranged from a public pledge by top Russian officials to resolve potential Arctic disputes peacefully under a United Nations treaty governing the law of the sea and to submit its territorial claims in the polar region jointly with Canada and Denmark, to a clash with Canada over an Arctic test flight by two Russian bombers in February.

Cannon has previously said Canada will not be "bullied" by Russia and will use its Canada First Defense Strategy to "take action" to protect sovereignty claims.

The government of Prime Minister Stephen Harper said it will spend billions of dollars to strengthen Canada's military presence in the North as part of its "use it or lose it" Arctic strategy.

Move for local role

But the Senate committee on energy, environment and natural resources has taken issue with the slogan.

Liberal Senator Grant Mitchell said the North is "not a frontier to be exploited. … It is a place to develop as northerners would have it developed."

To that end a report entitled "With Respect, Canada's North" said the 100,000 people who live in the Yukon, Northwest Territories and Nunavut should have a larger role in shaping policy for the region.

Committee members found climate change is dramatically affecting the lives of northerners and is advancing faster than expected, with melting permafrost causing buildings to tilt and creating roads like roller coasters, while rising sea levels are causing coastal flooding and hunters report declining caribou herds.

Senator Tommy Banks, also from the opposition Liberal party, said that while climate change is an "abstract concept" to southerners that "may or may not be happening, to the people of the North it's a fact of life."

The report recommended that the government provide more money for research in the North, with a greater emphasis on measuring climate-change trends, and called for more funding to help municipalities and the territorial governments adapt to the change. ●

NATURAL GAS

9th Circuit closes review of export license

The 9th Circuit Court of Appeals said it has closed its review of a federal decision to continue exports of liquefied natural gas to Asia from a terminal in Cook Inlet.

The announcement follows news May 12 that Chugach Electric, an Anchorage-area electric utility, signed a gas supply contract with ConocoPhillips, a local producer. ConocoPhillips owns the Kenai Peninsula export facility with fellow producer Marathon.

Following several years of deliberations, the U.S. Department of Energy last year extended the export license for the facility by two years, to 2011 from 2009.

The State of Alaska supported the extension in return for concessions from ConocoPhillips and Marathon, including a promise to negotiate with local utilities and to drill more wells.

Chugach challenged the export license, concerned about local utilities having adequate supplies. Proponents of the plant say it serves as a backup during times of high demand.

"This is a win-win for utilities that need gas to supply power and space heat to the bulk of Alaska's population and for Cook Inlet's oil and gas industry," Gov. Sarah Palin said in a statement.

The companies drilled the required wells last year. The newly proposed gas supply contract between Chugach and ConocoPhillips covers the final requirement of the deal.

The contract must still receive approval from the Regulatory Commission of Alaska before Chugach can start buying gas under it. The state said two Enstar contracts with ConocoPhillips and Marathon last year also helped satisfy the requirement. Regulators did not approve those contracts, instead allowing Enstar to buy gas using a provision in its tariff. Enstar is still looking to fill shortfalls in gas supplies expected as soon as 2011.

ConocoPhillips and Marathon were scheduled to appear before the Federal Energy Regulatory Commission on May 21 to discuss safety and reliability requirements at the LNG plant.

—ERIC LIDJI

● EXPLORATION & PRODUCTION

Carbon cuts beyond reach

Imperial CEO: Oil, natural gas, coal account for 80% of today's energy production, will satisfy demand for 'next few decades'

By GARY PARK
For Petroleum News

As Imperial Oil gears up for the expected start of construction on its Kearl Lake oil sands project, the company's Chief Executive Officer Bruce March is turning into one of the most outspoken promoters of the resource.

He told a University of Calgary policy forum on May 14 it is unrealistic to exclude the oil sands from North America's future energy mix given that the northern Alberta deposit represents 40 percent of the world's known oil resources that are outside the control of state-run companies.

March suggested that knowledge underpins President Barack Obama's seeming desire to find solutions to the oil sands' environmental problems rather than eliminating them from U.S. supply sources.

When Obama visited Ottawa in February "he could have said a lot of different things" about the oil sands, but "he didn't," March said.

"His plan will have less reliance on oil in the future, but his plan also has a strong factor of energy security," he said, suggesting that Obama believes the environmental challenge will "get solved up here in Canada very effectively."

However, March concedes the greenhouse gas emissions limits being mooted are beyond the reach of current technology and, currently, could only be achieved by lowering living standards.

California standards an issue

He was especially critical of the low carbon fuel standards that are moving towards legislation in California and that could become national U.S. policy, insisting that "no one knows how to make this fuel … that has 10 percent less life-cycle greenhouse gas emissions than the baseline as it's defined today. You'd have to go close to 100 percent ethanol to achieve that."

A set of draft standards released by the California Air Resources Board mandating a 10 percent cut in GHGs by 2020 has set off a fruitless scramble in Canada's petroleum industry to determine whether it can meet the standard, March said.

"No one knows how to make this fuel … that has 10 percent less life-cycle greenhouse gas emissions than the baseline as it's defined today. You'd have to go close to 100 percent ethanol to achieve that."
—Imperial Oil CEO Bruce March

"Initial work done by industry says it basically takes 100 percent ethanol vehicles — and a cellulosic ethanol; that's the key. Not corn-based ethanol."

California is aiming to lead the way in the construction of new biofuel facilities and replace 20 percent of the gasoline used by motor vehicles with alternatives such as electricity, biofuels and hydrogen.

March cautioned that the highly charged debate around the future of energy can lead to untested emotional responses.

He thinks a quick shift towards greater reliance on renewable energy sources is likely, although energy demand will depend on oil, natural gas and coal for the "next few decades," noting those three sources account for 80 percent of today's global energy production. However, he said government funding support for technology development might have a way of overcoming even the toughest challenges.

"At the end of the day, we are here to cooperate with the policy-makers," March said. ●

Shale threatens Alaska's plans

An Alaska Highway gas pipeline might crumble under the growing weight of shale gas production in the United States and Canada, said James Blanchard, a former U.S. ambassador to Canada.

He told a University of Calgary public policy forum May 14 that he doubts "Sarah Palin's pipeline is going to be built, not with the glut of natural gas in the U.S."

—GARY PARK

ALTERNATIVE ENERGY

GVEA reconsiders approach to Healy plant

Homer Electric Association back-out makes fate of Healy Clean Coal Project uncertain; HEA was to have bought power starting in '14

By STEFAN MILKOWSKI

For Petroleum News

The fate of the long-idle Healy Clean Coal Project is once again up in the air after the Homer Electric Association board on May 12 backed out of a deal with Golden Valley Electric Association and the Alaska Industrial Development and Export Authority to buy power from the plant starting in 2014.

Under the agreement, reached in January, AIDEA would have sold the plant to GVEA for $50 million and provided an additional loan of up to $45 million for work needed to restart it. HEA would have bought half the electricity produced by the 50-megawatt plant starting in 2014 under a long-term power purchase agreement with GVEA. And litigation between AIDEA, which owns the plant, and GVEA, which owns the property underneath the plant, would have ended.

At a public meeting on the project May 14 in Healy, GVEA President and CEO Brian Newton said HEA's decision will have a significant impact on plans to restart HCCP.

"If Homer exits, obviously we're going to have to go back and re-negotiate the asset sale purchase," he said, adding that the change will delay a final purchase agreement with AIDEA beyond the planned date of Aug. 1. "It changes the arrangements we have. It may even change the price; we're not sure. As soon as we find out from AIDEA that their contract is terminated with Homer, Golden Valley will again start negotiating with AIDEA."

Newton said using 100 percent of the power from HCCP could force GVEA to run other plants at partial capacity in certain circumstances, decreasing efficiency.

About 100 people showed up for the meeting, which lasted nearly two hours and included a presentation by Newton and questions from the public.

In a May 14 news release, AIDEA officials vowed to keep working to bring HCCP online despite HEA's decision. The $300 million publicly funded plant was completed in 1997 but has not run since early 2000.

HEA pulls out

Homer Electric Association, which currently gets 90 percent of its power through a supply contract with Chugach Electric Association that ends in 2013, had been eyeing the Healy Clean Coal Project for years. In November 2006, the utility reached an agreement with AIDEA in which HEA would get the plant running and use power from it. That plan was delayed by litigation between AIDEA and GVEA.

HEA made a separate offer in June 2008 in which GVEA would restart and operate the plant and sell power to HEA. GVEA never accepted the offer. The two utilities finally agreed to the terms of a power purchase agreement in the January deal reached with AIDEA.

Newly elected board Vice President Tim Evans told the Peninsula Clarion the board decided to move away from the coal plant because of concerns that it wouldn't be economic and wouldn't come online in time and because of widespread opposition from members of the cooperative utility. The board voted 8-1 in favor of a motion by Evans to cancel an RFP for a power supply study and move the cooperative "away from involvement in HCCP."

Evans told the newspaper that he had received hundreds of e-mails and calls about the plant. "Ninety-nine percent of them say 'no' to Healy," he said.

A group called HEA Members Forum quickly hailed the decision. "Unanswered questions about the functionality of existing plant equipment, new Clean Air Act permitting requirements, and the volatility of the coal market raise legitimate concerns that the costs of startup and buying half of the plant's energy output could greatly exceed present estimates and threatened to increase HEA member electric rates," spokesman Mike O'Meara said in a statement.

Environmental concerns

Opposition from environmental groups

see HEALY PROJECT page 10

STEFAN MILKOWSKI

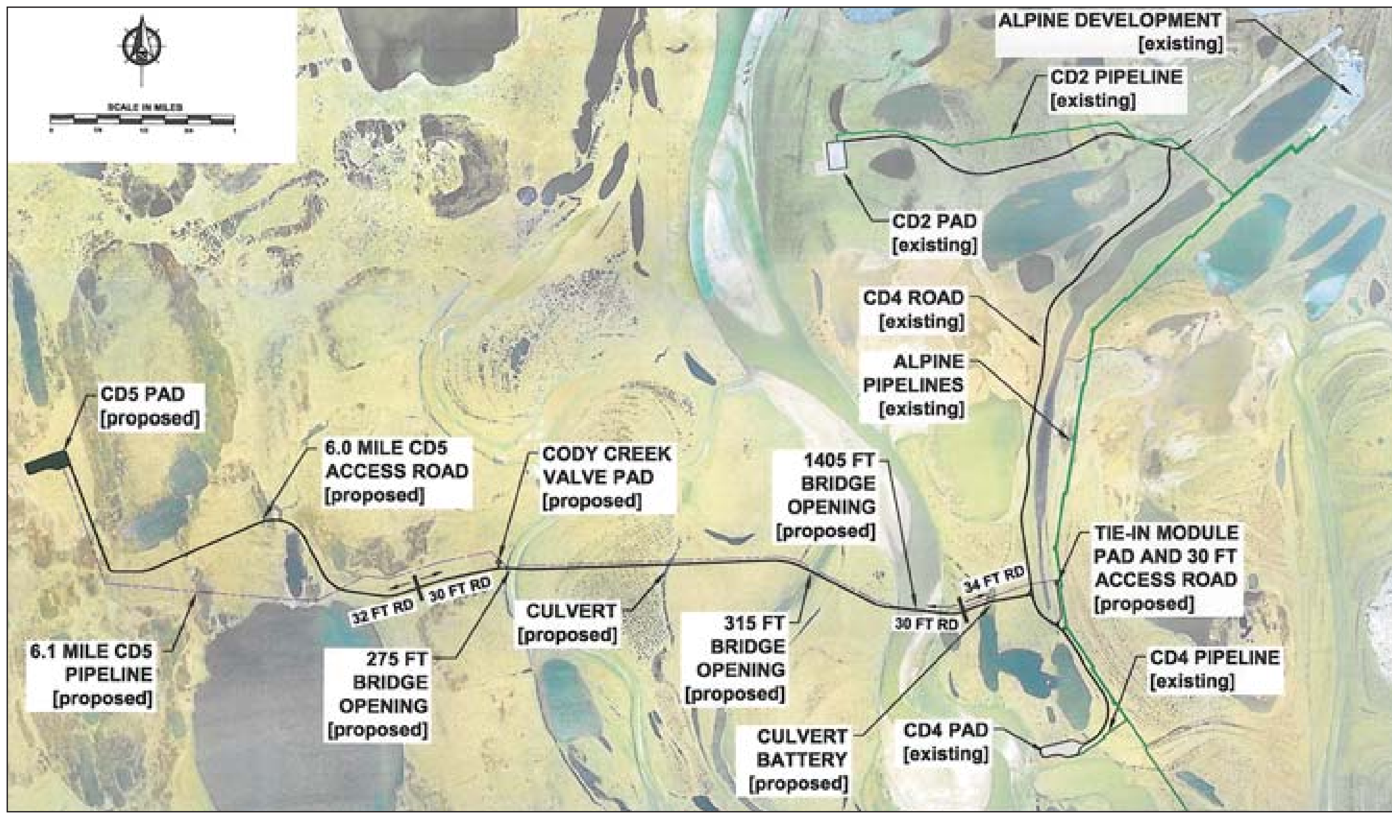
John Dailey of Ferry asks Golden Valley Electric Association President Brian Newton about the impact of Homer Electric Association's backing out of a deal to restart the long-idle Healy Clean Coal Project. GVEA held a public meeting on the restart May 14 in Healy.

● EXPLORATION & PRODUCTION

Conoco files new Alpine West application

Compared to 2005 proposal, new plan for first production from NPR-A, with pad 3 miles to south, includes larger pad, more wells

By KRISTEN NELSON
Petroleum News



Proposed Alpine West project (CD-5) showing road, pipelines, bridges and drill site.

ConocoPhillips Alaska has restarted permitting efforts for its CD-5 Alpine satellite development, Alpine West, which will be the first production from the National Petroleum Reserve-Alaska. ConocoPhillips began permitting this project with the U.S. Army Corps of Engineers in 2005, but withdrew that application.

The corps said the current application is for a larger pad with more wells than the 2005 application: as many as 33 wells at CD-5 (compared to up to 22 wells in the 2005 application); one large and two small bridges (the 2005 application had one large and one small bridge); pad size is 11.7 acres (compared to 9.8 acres); and 6.3 miles of access road (compared to 4.4 miles).

The increase in the number of wells is based on drilling at Alpine, the main producing field in the Colville River unit, since the 2005 application, ConocoPhillips Alaska spokeswoman Natalie Lowman told Petroleum News in an e-mail.

The increase in wells to a maximum of 33 at CD-5 "came about because recent drilling information from existing Alpine pads gave us more data that positively changed our view of the resources," Lowman said.

New pad, bridge sites

The revised site for the CD-5 Alpine satellite pad, Alpine West, will be in section 18 of township 11 north, range 4 east, Umiat Meridian, some 3 miles south of the 2005 proposed pad site in section 8, township 11 north, range 4 east, UM. The revised access road would converge with the existing road near the CD-4 pad south of the main Alpine processing facilities. Alpine is not connected to the North Slope road system, but two of its drilling pads, CD-2 and CD-4, are connected to the main CD-1 drilling and processing pad by all-weather gravel roads.

The CD-5 drill pad access road would include a 1,405-foot bridge over the Nigliq channel of the Colville River, a 317-foot bridge over a paleochannel at Lake L9341 and a 277-foot bridge over Cody Creek.

The Nigliq channel bridge has been relocated from the 2005 proposal based on consultation with Kuukpik Corp. — the village corporation at Nuiqsut and the surface owner in the area — and other stakeholders from the village of Nuiqsut to mitigate potential subsistence impacts.

The corps said the project design revisions primarily involve location and size of the CD-5 drill site, the access road and the Nigliq Channel crossing.

The new bridge location is just north of the CD-4 drill site.

ConocoPhillips told the corps the new bridge location "incorporates local knowledge provided by Kuukpik shareholders for the purposes of reducing ice jamming, providing for high and stable banks, avoiding popular subsistence fishing areas, and avoiding historic landmarks."

Pile-supported bridges

The Nigliq channel bridge will be constructed on nine steel pile piers, with a 200-foot span over the navigation channel and the remaining piers some 174 feet apart. The corps said each pier section would include six 48-inch-diameter support steel piles and one 48-inch ice-breaking pipe. The pipeline system would be supported on the proposed bridge crossings on the downstream side, the corps said.

The bridges will carry vehicles and pipelines, but the bridge design will not support a full drilling rig, the corps said.

The bridge will have a concrete deck, as will the bridges at Lake L9341 and Cody Creek. The Lake L9341 bridge will have seven steel pile piers; the Cody Creek bridge will have four steel pile peers.

The 6.1-mile elevated pipeline system would generally parallel the access road, with 24-inch-diameter steel vertical support members some 55 feet apart. The pipelines will rest on horizontal support members 7 feet above ground elevation; 725 vertical support members will be required.

The pipeline system will include miscible injectant and seawater injection pipelines from CD-1 at Alpine, power and communications utility lines, a production pipeline to transport CD-5 produced fluids (crude oil, gas and water) to CD-1 for processing and a pipeline to transport lean gas from CD-1 to CD-5 for artificial lift.

Access for future developments

CD-5 will initiate Alpine satellite development in NPR-A, and the access road is intended to provide access for future satellite developments to the Alpine processing facility.

ConocoPhillips said foreseeable future developments include several drill sites west of the Colville River Delta which would develop small oil accumulations as satellites to the Alpine field.

Alpine West, at CD-5, would be the first Alpine satellite west of the Nigliq channel, the company said.

Successive satellites under evaluation include Lookout CD-6, CD-7 and Fiord West, but ConocoPhillips said discussions of those developments "are preliminary in nature and subject to change."

Development of CD-6 would likely follow CD-5, the company said, followed by CD-7 and Fiord West. "Additionally, one or two unidentified drill sites may be tied into this NPR-A infrastructure if future exploration efforts in the vicinity prove successful."

Lookout CD-6 and CD-7 are in the Greater Mooses Tooth unit in NPR-A, ConocoPhillips said, and nomenclature for those will change to GMT to distinguish developments in Greater Mooses Tooth from developments in the Colville River unit.

Sequential development

The company said sequential development and infrastructure sharing were key aspects of NPR-A development.

The value of sequential development is that each new drill site benefits from technology advancements and lessons learned, the company said. Sequential satellite development "allows for level resource loading as engineering, drilling and construction teams transition from one NPR-A project to the next," minimizing construction support infrastructure and creating jobs and opportunities "for a sustained period of time."

Sequential development also "maximizes use of existing facilities and mini-

see ALPINE page 9

continued from page 8

ALPINE

mizes the need for future Alpine field processing facility expansions, resulting in the extension of the economic life of these resources," and increasing ultimate oil recovery, "cash flow for investors and royalty owners, and economic opportunities for local residents."

More than 20 wells have been drilled during the eight exploration seasons since the 1999 Northeast NPR-A lease sale, but "the volume of oil discovered within the Northeast NPR-A is insufficient to economically support development of new standalone processing facilities," ConocoPhillips said.

By sharing the Alpine pipelines, processing plant, airstrip, roads, drilling support infrastructure and operations base camp, "several of these small oil accumulations can be developed to benefit multiple stakeholders, including local residents, Alaska Native corporations, the North Slope Borough, the State of Alaska and the federal government," the company said.

Potential projects

Lookout GMT-1, formerly CD-6, would be a pad some 8 miles southwest of Alpine West CD-5. ConocoPhillips said GMT-1 is anticipated to be the first Greater Mooses Tooth development produced through Alpine following development of Alpine West.

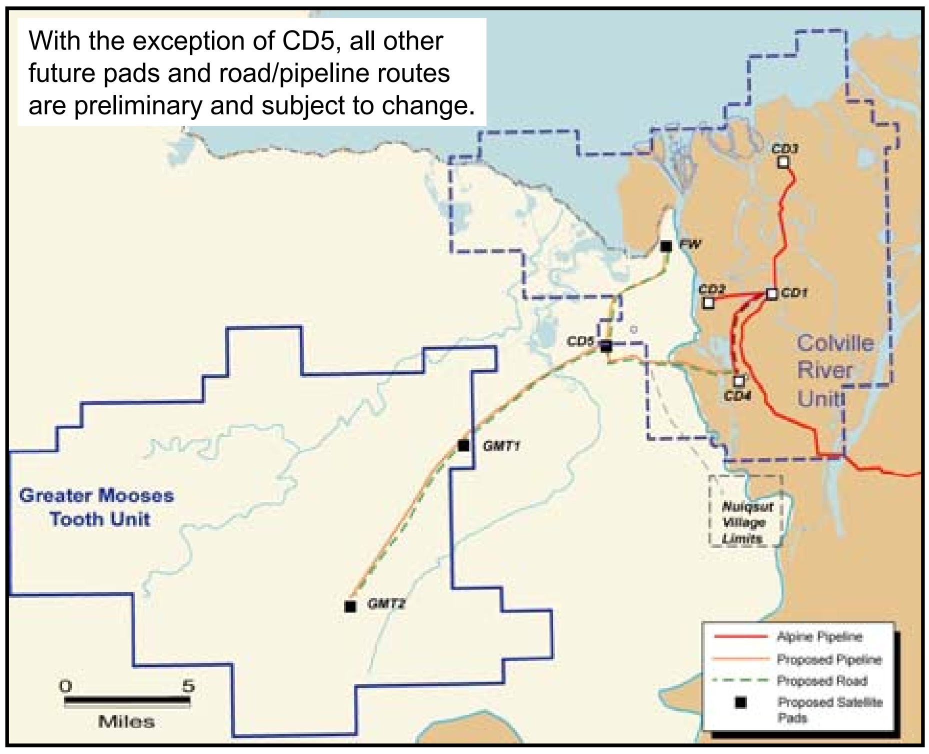
Plans are not final, the company said, but the base plan calls for eight wells, with an upside of 16 wells.

GMT-2, southwest of GMT-1, formerly called CD-7, is still under appraisal, the company said, but the base plan calls for 10 wells with an upside of 19 wells.

Fiord West planning is a result of appraisal wells drilled since 2004, the company said, including Iapetus and the Char No. 1, with positive results from the Char well confirming a potential satellite development about 4.5 miles north of Alpine West, an area identified in the 2004 Environmental Impact Statement as CD-12.

"This accumulation could be developed on either the east or west side of the Nigliq channel. ConocoPhillips is evaluating placing the Fiord West pad on the west side of the channel to minimize additional infrastructure in the Colville River Delta," the company said.

While Fiord West is in the early conceptual planning stage, the company said the current plan assumes a development with 20-25 horizontal wells drilled from a gravel pad upsized to accommodate 39 wells, with an injection method of miscible water-alternating-gas.



Colville River and Greater Mooses Tooth units with existing drill sites and facilities (CD-1, CD-2, CD-3, CD-4), Alpine West project (CD-5) and other proposed drill sites (GMT-1, GMT-2 and Fiord West).

Kuukpik spur road, lay-down area

ConocoPhillips said the Kuukpik Corp. or a Kuukpik affiliate may "construct, own and maintain" a spur road from Nuiqsut "to a mutually agreed tie-in location on the CD-5 industry road."

The company said it has a longstanding commitment to contribute to the costs to construct such a road, which "would allow easier access for local residents to economic opportunities, such as oil industry jobs, and to subsistence hunting and fishing areas."

The spur road would be some 5.8 miles long, but is not part of ConocoPhillips' applications, the company said.

Another project not part of the company's applications is a possible "lay-down" area for industry use which would be built by Kuukpik Corp. or a Kuukpik affiliate. ConocoPhillips described this as an area for storage of support equipment to the west of and outside the Colville River delta, which would reduce activities inside the delta.

First production end of 2012

Permits are required before the project will go to the ConocoPhillips board for approval, but subject to project approval, ConocoPhillips said the CD-5 development schedule would begin in the fourth quarter of 2009 with ordering of long-lead materials for the Nigliq channel bridge.

Ice road construction would begin in the fourth quarter of 2010 in support of CD-5 construction; first quarter 2011 work would include construction of the gravel road, pad, bridge piers and substructure.

There would be gravel mining and construction activities in the summer of 2011, and ice road construction would begin again in the fourth quarter of 2011 in support of construction.

First-quarter 2012 work would include installation of vertical support members, pipelines and bridge superstructure.

On-pad facilities would be constructed in the second and third quarters of 2012.

Drilling would begin in the second quarter of 2012 with first production in the fourth quarter of 2012. Drilling is expected to take 12 to 16 months.

ConocoPhillips is the operator at the Colville River and Greater Mooses Tooth units; Anadarko Petroleum is a partner in both units. ●

FINANCE & ECONOMY

Oil drops below $62 as big rally pauses

Oil prices eased off six-month highs May 21 in Asia after rallying the day before to above $62 a barrel on a bigger-than-expected fall in U.S. crude inventories.

Benchmark crude for July delivery was down 50 cents to $61.54 a barrel by late afternoon in Singapore in electronic trading on the New York Mercantile Exchange.

Oil has surged about 75 percent since March on signs the global economy, while still struggling through a severe slowdown, may have avoided a worst-case scenario.

On May 20, the July contract rose $1.94 to settle at $62.04 after the government said U.S. crude inventories fell for a second week, suggesting demand may be improving.

Crude stockpiles dropped by 2.1 million barrels for the week ended May 15, according to Energy Department's Energy Information Administration; gasoline inventories dropped by 4.3 million barrels.

That was a bigger decline than analysts had expected, especially for gasoline. Still, oil supplies remain at 19-year highs, and some analysts question whether the recent jump in prices is justified when weak remains weak.

"The inventory data is looking better but demand is still soft," said David Moore, commodity strategist at Commonwealth Bank of Australia in Sydney. "To my mind, the oil price has risen prematurely and ahead of fundamentals."

The oil rally has mirrored gains in stocks as investors bet the worst of the global economic downturn may be over.

"There's a broadly less pessimistic view of the international outlook, which is encouraging people to get into oil," Moore said.

In other Nymex trading, gasoline for June delivery fell 0.60 cent to $1.80 a gallon and heating oil dropped 0.86 cents to $1.53 a gallon. Natural gas for June delivery slid 1.1 cents to $3.96 per 1,000 cubic feet.

—THE ASSOCIATED PRESS

ALTERNATIVE ENERGY

Coal-to-diesel plant faces problems

Fairbanks officials are hoping to build a coal-to-diesel plant near Eielson Air Force Base. But obstacles are mounting in trying to coordinate with the military, placing a $10 million federal earmark in jeopardy that would move the project along.

U.S. Sen. Lisa Murkowski says a top Air Force official has told her the military will work with Fairbanks officials about concerns that the joint endeavor is off track.

Former Sen. Ted Stevens worked $10 million into the Air Force budget, earmarking the money for phase-two studies of a coal-to-liquids project at Eielson.

—THE ASSOCIATED PRESS

continued from page 7

HEALY PROJECT

also threatens to slow or halt the restart of HCCP.

A coalition of local and national groups including the Sierra Club, the National Parks Conservation Association and the Denali Citizens Council contends that GVEA will have to comply with the "prevention of significant deterioration" provisions of the federal Clean Air Act. The provisions, which apply to new and renovated facilities, would require that the plant use the best available technology to control pollution and not violate any current air quality standards. In an April 29 letter to GVEA's Newton, lawyers representing the groups urged the utility to comply with the provisions as if it were a renovated facility.

At the meeting in Healy, Newton promised to seek the opinion of the Alaska Department of Environmental Conservation on the issue. But he added that GVEA officials don't believe the plant will need to comply with the provisions because the plant has already been permitted and is not being renovated.

"We feel that the plant has been in warm lay-up status," Newton said. "The plant was always intended to run. It has not been mothballed. The systems have been kept active. … Therefore it's not a re-activation; it's simply just a restart of the plant."

Newton said after the meeting that the Healy plant was not designed for current pollution control technologies and may not be able to accommodate them. Even if it could, he said, the cost of retrofitting the plant with new technology would be "phenomenal."

"That's not what we're willing to do," he said.

GVEA secured a Title V operating permit for the plant in 2003. The permit came up for renewal in 2008 and was administratively extended pending public comment and renewal, according to Newton.

Newton said he expects the National Park Service to oppose the permit renewal, despite settlement agreements made with the agency and environmental groups in the mid-'90s before construction of the plant.

Climate change

Climate change legislation could also affect the economics of the plant.

Newton said GVEA will operate the facility with the "clean coal" technology originally installed, which is meant to minimize pollution from nitrogen and sulfur oxides. But he added that technology to capture and store carbon dioxide, the main pollutant linked to global climate change, "just isn't there."

Newton said the plant would still make economic sense even if the utility were forced to pay $20 to $40 per ton of carbon dioxide emitted under a cap-and-trade program like the one currently before Congress.

He said utility officials expect to produce power from HCCP for 9 or 10 cents per kilowatt-hour, assuming 85 percent availability and 25-year debt. ●

● NATURAL GAS

Ramras wants more scrutiny of FNG

Believes utility is earning enough to justify further look into rate regulation; company says profits only shouldn't be trigger

By ERIC LIDJI
Petroleum News

A Fairbanks legislator is again asking regulators to examine the balance sheets of a natural gas utility to see whether economic regulation might be appropriate.

In a May 8 letter to Chairman Bob Pickett, Rep. Jay Ramras, R-Fairbanks, asked the Regulatory Commission of Alaska to study the earnings of Fairbanks Natural Gas.


SARAH HURST
JAY RAMRAS


DAN BRITTON

Ramras believes a review of the 2008 earnings would show the company is earning a rate of return above that of other natural gas utilities in Alaska, such as Enstar Natural Gas.

"This renewed scrutiny is warranted in this case," Ramras wrote.

The letter followed comments Ramras made at a May 6 hearing in Fairbanks. The hearing was a chance for Fairbanks Natural Gas and the state Attorney General's office to present the terms of a deal to stave off regulation for the utility in return for concessions.

Ramras said recent testimony suggesting re-regulation wasn't appropriate was based on 2007 financial figures, but that Fairbanks Natural Gas' earnings increased in 2008. He also said company President Dan Britton received a higher salary from year to year.

Fairbanks Natural Gas said regulation shouldn't be based on a few profitable years.

"To go back and pick out a year and say, 'Okay, now you're earning more than you earned last year' is not really relevant to the underlying question before us, which is: Should they be regulated on an ongoing basis in every year, not just one out of 10, say," Fairbanks Natural Gas attorney Mark Figura said at the hearing, according to a transcript.

Concerning the salary, Britton has said much of the jump can be attributed to his change in status from contract to salaried employment, and not to an actual increase in payment.

On the Web

See previous Petroleum News coverage:

"Another look at regulation for FNG," in June 15, 2008, issue at www.petroleumnews.com/pnads/153683274.shtml

"AG witnesses sour on re-regulating FNG," in Nov. 9, 2008, issue at www.petroleumnews.com/pnads/251001265.shtml

"AG, FNG propose regulation deal," in April 5, 2009, issue at www.petroleumnews.com/pnads/187353002.shtml

Issue playing out for years

Fairbanks Natural Gas began life as an economically regulated utility, meaning it needed the approval of regulators to change rates. The RCA lifted that restriction in 2003, saying the utility needed agility to compete with the dominant fuel oil companies in Fairbanks.

Following a supply scare in 2006, Ramras began pushing for regulators to keep a more watchful eye on Fairbanks Natural Gas. In May 2008, Ramras and more than a dozen lawmakers from Southcentral asked the RCA to consider re-regulating the utility's rates.

The request came after Fairbanks Natural Gas posted a profit after many years of losses.

The lawmakers decided not to be a party in the case and so the Attorney General joined the case on behalf of the public. A pair of witnesses for the Attorney General ultimately testified that economic regulation wasn't appropriate now, but could be in the future if Fairbanks Natural Gas ever captured a large enough share of the home heating market.

One of the witnesses even said Fairbanks Natural Gas might be entitled to higher returns as a regulated utility than it was currently earning as an economically unregulated utility.

Fairbanks Natural Gas said profit alone shouldn't trigger regulation, because the point of deregulation was to let the company use earnings from good years to recover its losses.

Looking to resolve the matter, the utility and the Attorney General proposed a deal to tether residential rates to those paid by large commercial customers, along with other concessions. Large commercial customers typically get a discount for buying in bulk.

The RCA hasn't yet decided whether to approve the deal.

Price comparisons volatile

The recent volatility in fuel prices created an unusual marketplace in Fairbanks.

For years, Fairbanks Natural Gas marketed itself as the cheaper alternative in a city where fuel oil companies try to offer a better price by just a few pennies on the gallon.

Trouble securing gas supplies from Cook Inlet forced Fairbanks Natural Gas to increase prices, leading to a stretch where natural gas actually cost more than fuel oil in Fairbanks.

That changed last spring and summer as crude oil prices rose to record peaks, taking fuel oil prices with it. Natural gas once again became the cheaper fuel in Fairbanks.

Now that prices have fallen, natural gas is again the more expensive option. During the hearing, it was revealed that the Princess Riverside Lodge — the building where the hearing was taking place — and other customers had switched back to fuel oil from gas.

Some larger customers, like the Fairbanks Independent School District, have the ability to switch back and forth between the fuels as prices dictate. The concern from regulators is whether the utility's residential customers are "captive," or unable to easily switch fuels.

Britton said his company's goal is to be a cheaper alternative to fuel oil, but that can be difficult in periods like now when oil prices fall and costs to deliver natural gas increase.

Fairbanks Natural Gas liquefies fuel from Cook Inlet and trucks it north to Fairbanks.

Last year, the utility signed an agreement to buy North Slope natural gas from Exxon, but still needs to build a liquefaction plant before it can start trucking the fuel south. ●

SAFETY & ENVIRONMENT

Murkowski, Begich introduce escort bill

U.S. Sens. Lisa Murkowski, R-Alaska, and Mark Begich, D-Alaska, introduced legislation May 14 that would require all tankers transporting oil in Alaska's Prince William Sound to be escorted by at least two towing vessels, as has been the practice for the past 20 years.

In a statement the two said that the current tanker safety system, authorized in the Oil Spill Pollution Act of 1990, applies only to single-hulled tankers, which are being phased out, with the last single-hulled tanker in the Prince William fleet expected to be retired by August 2012.

The legislation would require dual escort vessels for double-hulled tankers.

In a statement prepared for the floor, Murkowski said that while double-hulled tankers are currently escorted by two escort tugs capable of assisting the tanker in the case of emergency — as are single-hulled tankers — the legislation would maintain the existing escort system in place for all tankers.

The senator said that while there have been "a number of marine incidents and near misses since the Exxon Valdez Oil Spill in 1989, over the past 20 years, through the efforts of the U.S. Coast Guard, industry, the State of Alaska and the Prince William Sound Citizens Advisory Council to implement the requirements of OPA 90, there have been no major oil spills."

In the senators' joint statement Begich said, "The tractor tugs have proven their usefulness several times when tankers needed assistance. Their continued use is inexpensive insurance to protect the environment of Prince William Sound and maintain the flow of oil."

U.S. Rep. Don Young, R-Alaska, is working with fellow members of the House Committee on Transportation and Infrastructure on a House version of the provision.

—PETROLEUM NEWS

Petroleum news

Business Spotlight

Arctic Slope Telephone Association Cooperative Inc.

FORREST CRANE

Jodi Forsland, Chief Services Officer

ASTAC was formed more than 30 years ago, bringing the first reliable, modern telecommunications services to the communities of the North Slope. As a cooperative its mission is to improve the quality of life for all the people it serves, providing voice, data and wireless service to the North Slope.

Jodi Forsland joined ASTAC in December 2008 with more than 20 years experience in the telecommunications industry. Her career started in customer service and training; she then moved to marketing and product development and leadership roles at both ACS and AT&T. Jodi was born in Anchorage and enjoys the outdoors and spending time with her husband Dave, five grown children and grandchildren at their cabin in Big Lake.

—MARTI REEVE

Unique Machine

FORREST CRANE

Tony Carey, General Machine Foreman

Unique Machine, a Sumitomo Corporation of America subsidiary, is Alaska's largest machine shop and has served the fishing, mining, construction and oilfield industries, and government, for more than 30 years. It was the first manufacturing facility to be ISO certified and is licensed to thread all major API and proprietary oilfield threads.

Tony Carey joined Unique Machine in April of 2006 with 22 years experience as a machinist. Tony brought with him the ability to visualize and sort out the details, focusing on a solution and getting the job done. In his time off, Tony enjoys motor sports, golfing, hunting and fishing. He currently lives in Anchorage with his spouse of 28 years and three great children.

—MARTI REEVE

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

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● GOVERNMENT

B.C. election gives life to carbon tax

Campbell victory seen as proof voters accept carbon tax, which covers fuels, coal, natural gas, believing it makes a difference

By GARY PARK
For Petroleum News

The election of Gordon Campbell to lead British Columbia for another four years carries weight with climate change advocates through the western region of North America.

The first leader on the continent to impose a carbon tax, Campbell's victory is seen as clear proof that voters are ready to swallow a tax if they believe it makes a difference to the environment.

For British Columbia, despite pledges by the opposition New Democratic Party to abandon a tax seen as unfair to northern residents, businesses, farmers, ranchers and truckers, the tax has been in place for almost a full year.

It started at 2.41 cents per liter of gasoline, rising progressively to 7.24 cents in 2012, and almost 50 cents per gigajoule for natural gas, building to C$1.50 in 2012. The tax covers gasoline, diesel, natural gas, heating fuel, propane, aviation fuel, kerosene and coal.


GORDON CAMPBELL

But the government also linked the tax to cuts in both personal and corporate tax rates, effectively rendering the tax as revenue neutral.

Basking in the afterglow of the election, Campbell told reporters "there's an important message that (the tax) doesn't mean the end of your political mandate."

Regardless of reports that some cabinet ministers and members of his caucus were either flat-out opposed to the tax, or uneasy about its impact on their political careers, Campbell believes the majority believed that "what we did is important."

Win could embolden others

That importance could embolden other governments in Canada, as well as U.S. members of the Western Climate Initiative, which was formed early in 2007 to combat global warming.

In addition to the Canadian provinces of B.C., Manitoba, Ontario and Quebec, the partners include seven U.S. states — Arizona, California, Montana, New Mexico, Oregon, Utah and Washington. Alaska is one of six states listed as an observer, along with five states in Mexico and Saskatchewan. Notably absent is Alberta, a resolute foe of cap-and-trade.

The WCI is trying to figure out ways to collectively reduce greenhouse gas emissions, with partners required to set overall targets and develop a market-based, multi-sector mechanism to achieve those goals.

It has already rolled out a plan for a cap-and-trade proposal to be launched in 2012, followed by a broader cap on carbon emissions in 2015.

The WCI's goal is to reduce GHGs by 15 percent from 2005 levels by 2020.

But the concept seemed to take a setback in Canada last year when former Liberal leader Stephane Dion, who called for a carbon tax, was defeated in an election by Prime Minister Stephen Harper.

Ian Bruce, climate change specialist with the David Suzuki Foundation said Campbell's electoral success is a "watershed moment for action" on climate change in North America.

He said the vote showed British Columbians cared and now expect the Campbell government to deliver a comprehensive action plan on climate change.

Matt Horne, director of the B.C. Energy Solutions Program for the Alberta-based Pembina Institute, said Campbell's victory is encouraging for any government trying to decide whether to put a price on carbon, adding that the people of British Columbia have conclusively shown they want bold action. ●

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NIKAITCHUQ

material to the North Slope.

2010 sealift for modules

According to the state, Eni now plans to "fully complete the production modules in Louisiana with a sealift date of 2010," and will finish drilling early production wells once those modules have been installed. Eni already drilled one production well at the unit.

Eni is developing Nikaitchuq with both onshore and offshore facilities, drilling up to 26 wells from Oliktok Point, and more than 50 additional wells from an offshore site near Spy Island. The company plans to connect the two sites with an underwater pipeline.

The facilities will be the first on the slope not owned by BP, ConocoPhillips or Exxon.

The missed sealift helps reconcile a contradiction surrounding the delays.

Reports suggested low oil prices played a large role in the decision to delay development, but the state planned for that contingency by modifying its royalty structure on several leases at Nikaitchuq. The change allowed Eni to pay lower royalty rates to the state if Alaska North Slope crude oil fell below an inflation-adjusted price of $42.54 per barrel.

ADL 391283 gets reprieve

The state also agreed to extend the deadline for including one lease in the unit — ADL 391283 — in a participating area by one year, to Oct. 5, 2010, from Oct. 5, 2009.

The acreage contained in the lease was originally part of the Kuparuk River unit, added through expansions in the mid to late 1980s. But the Kuparuk River unit owners farmed out some of the acreage to Eni in 2007, and the state called the new lease ADL 391283.

The addition of ADL 391283 to Nikaitchuq came as part of a 2007 state decision to expand the Nikaitchuq unit to include the leases of the neighboring Tuvaaq unit.

The Nikaitchuq unit covers some 33,870 acres spread across 18 state oil and gas leases. ●

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RALLY

lion bpd higher than current volumes, which explains why Total is betting so heavily on a future in the heavy oil plays of Canada and Venezuela.

"We believe that, because of plateau oil, the oil sands are necessary to supply demand growth," said Yves-Louis Darricarrere, Total's exploration and development president.

In fact, Total has earmarked up to US$20 billion in spending over the next decade to enlarge its presence in Alberta.

Although the company abandoned its hostile bid for UTS Energy, which owns 20 percent of Petro-Canada's Fort Hills project and 50 percent of three oil major leases, there is a continuing rumble that Total may return to the scene of the battle or possibly launch a fresh takeover offer for OPTI Canada, which owns 35 percent of Nexen's Long Lake project.

Bolstering Total's outlook is a 4 percent decline in British North Sea production, despite heavy investment in production and reserve technology, and a decline in Mexico's Cantrell field (recently the world's second largest producer) that is two or three times faster than the North Sea.

Of the non-OPEC production, 70 percent comes from seven countries, of which only Canada is adding to its production every year, while Saudi Arabia is the only OPEC country to post increases.

Mixed results

Despite its already substantial holdings in the oil sands, Total's experience is not always one of unmixed success. The combination of roller-coaster oil prices and technological setbacks has raised its economic break-even point to US$80 per barrel, but that has not deterred it from pushing ahead with plans for a heavy oil upgrader near Edmonton of 130,000-230,000 bpd at a cost of up to C$10 billion.

Regardless of the steep learning curve — and having a major role in Canada and Venezuela means Total can share its hard-won knowledge in both countries — the French oil giant sticks resolutely to its belief that the oil sands have a certain future and its commitment to become a major participant in the resource.

OPTI, which brought a new extraction technology to Long Lake, could be an obvious target, if you accept reports that it is struggling to cover its share of the C$6.5 billion project.

And should Total make a bid for OPTI that would revive talk last year that it was eying a takeover run at Nexen.

StatoilHydro also resolute

Equally resolute in its determination to plug on in Alberta is Norway's StatoilHydro, which said it has no plans to withdraw from the oil sands in the face of opposition from environmental and political attempts to force a withdrawal.

Greenpeace wants StatoilHydro to abandon its C$2.2 billion acquisition two years ago of North American Oil Sands Corp., which controlled 257,000 acres of leases and 2.2 billion barrels of recoverable reserves.

The Norwegian company — the world's fourth largest oil exporter — followed up that deal by announcing it was ready to spend US$15 billion to attain production of 200,000 bpd by 2020, describing the oil sands as a "very important and high focus" element of its international portfolio.

In addition to Greenpeace's campaign, Norway's Christian Democratic Party (a small voice in the parliament) will ask for a vote on whether StatoilHydro should be forced to withdraw from the oil sands.

Bob Skinner, senior vice president of the company's Canadian unit, told the Financial Post that StatoilHydro's oil sands strategy remains on track and will not be reconsidered.

But the proposed C$19 billion merger of the two Canadian energy giants is encountering choppy water, with Letko Brosseau & Associates, a Montreal firm with about 2.1 percent of Petro-Canada's shares, objecting to the fact that Suncor will control 62 percent of the new entity.

He said a demonstration project is 50 percent completed and its application for a larger separate development will remain before regulators.

That approach was resoundingly endorsed May 19 by StatoilHydro shareholders, who voted 99.85 percent to support their company's role in the oil sands, rejecting calls to withdraw from Canada.

Norway's deputy petroleum and energy minister Robin Kaass, said it would be "unnatural" for the Norwegian government to overrule a decision by the StatoilHydro board, although the company will be held to the "highest standards for ethics and the environment."

Devon will focus on sands

Adding to the upbeat messages, Devon Energy, the largest independent producer in the United States, said it will focus on building its oil sands presence, while scaling back discoveries in the Gulf of Mexico because the oil sands need less capital to build.

Devon President John Richels said earlier in May that the company's wholly owned Jackfish development is also benefiting from a softer Canadian dollar, some cost reductions and improved access to labor.

As a result, Devon is pushing ahead with the second stage of Jackfish, costing about US$1 billion, funding the work with cash flow from the first phase.

Japan Canada Oil Sands, a wholly owned unit of Japan Petroleum Exploration Co., also updated an assessment of its Hangingstone lease, held jointly with Nexen, where it currently pumps 8,500 bpd.

Japan Petroleum with 75 percent (including 3.75 percent for Japan Canada) and Nexen with 25 percent estimate they can raise the output to 35,000 bpd over 25-30 years starting in late 2014.

The information is contained in a documents filed with the Alberta government as part of an environmental impact assessment.

Connacher ramping back up

At the other end of the scale, UTS Energy and Connacher Oil and Gas are making positive noises about their oil sands plans.

Connacher, a startup company, was one of the first to shelve its expansion plans last year when the economy went into a tailspin and is now one of the first to come back to life, boldly declaring it has "weathered the storm" of low oil prices.

Chief Executive Officer Dick Gusella said Connacher is ready to resume ramping up production at its Great Divide project in Alberta, five months after stalling progress.

He told analysts that Connacher is confident it can again achieve its objective of "stable and sustainable production" at or close to plant capacity of 10,000 bpd in the second half of 2009.

"With rising oil prices and lower costs and continued narrow differentials for heavy oil due to bottom market considerations, we now have healthy, positive and improving bitumen netbacks which augurs well for future growth" in the in-situ sector, he said.

Current output at Great Divide is 8,000 bpd and operating costs are targeted at C$15-$17 per barrel for the balance of 2009, which would make Connacher one of the low-cost oil sands operations, Gusella said.

He said the company has also lined up new markets for its bitumen from regional upgraders.

Gusella denied rumors that Connacher is squeezed for cash, saying the company had a cash balance of C$100 million at the end of March and forecast positive cash flow in the current quarter and further improvements over the second half.

If oil holds steady at US$45 per barrel WTI "we will have sufficient funds to meet all our obligations and still end up with surplus cash," Gusella said.

UTS thinks cost could fall

UTS, emerging from its battle with Total, said May 13 it has enough funding in place to cover its share of Fort Hills' development, if the project goes ahead after the Petro-Canada and Suncor Energy merger closes.

The company said on its Web site that it would not have to obtain any financial backing if estimated costs of Fort Hill's initial 160,000 bpd phase keep falling.

Petro-Canada, which is 60 percent operator, said in April that the changed economic environment, with labor and materials costs undergoing rapid change, means the first-stage budget has declined to C$10 billion from C$14 billion and UTS said it may now actually cost closer to C$8 billion.

UTS Chief Executive Officer Will Roach said the latest cost estimates "reflect the new business environment and the reality are currently in."

In a best-case scenario, UTS also thinks that estimate could fall to C$5 billion if there is a dramatic change in the scope of Fort Hills and the project could benefit from a union of Suncor and Petro-Canada facilities, including access to electricity and hot water from Suncor.

But the proposed C$19 billion merger of the two Canadian energy giants is encountering choppy water, with Letko Brosseau & Associates, a Montreal firm with about 2.1 percent of Petro-Canada's shares, objecting to the fact that Suncor will control 62 percent of the new entity.

Daniel Brosseau, the firm's president, argued Petro-Canada represents more than 60 percent of the cash flow, reserves and production, while its asset values at least match those of Suncor.

The investment firm said it is aware of a second major investor that shares its concerns, although it has not yet attempted to build support among other shareholders. ●

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STUDY

can move ahead of government climate-change legislation.

Those two issues will "shape all growth of the oil sands," said Daniel Yergin, chairman of Massachusetts-based CERA and author of The Prize, the Pulitzer Prize-winning book on the history of the global oil industry.

But the study, entitled "Growth in the Canadian Oil Sands: Finding a New Balance," compiled over the last eight months and released May 18, is in no doubt that the oil sands "have moved from the fringe of energy supply to the center. … They are now one of the major resources in the world with potential for very substantial expansion."

"More than ever before, North America's daunting energy, environmental and economic challenges require a careful balancing of oil production, energy security, social and environmental impact (including greenhouse gas emissions) and economic growth," said a backgrounder to the study.

It described the oil sands as the largest and most complex upstream play in North America, "which lies at the convergence of all the challenges facing the continent."

"The choices that governments, companies and communities make in managing the interplay of these challenges will be critical in determining the pace and outcome of investments in Canadian oil sands," CERA said.

The oil sands ranked Canada No. 4 on the study's list of the top 15 countries in the world, based on their potential to raise production over the next decade, with Canada and Brazil the only Western Hemisphere countries to find a place on the list.

Yergin said the resource faces the "double challenge of cost and environmental questions (to which) innovation is the answer on both fronts."

Alberta production could grow

Despite the risks hanging over the oil sands, CERA said it is possible for production from northern Alberta to climb over the next 25 years to 6.3 million barrels per day from today's 1.8 million bpd.

The study determined that oil sands projects need crude prices of US$60-$85 per barrel to be economic.

Under three scenarios for oil sands development, CERA estimates production could range from 2.3 million bpd to 6.3 million bpd by 2035, with the low-growth outcome reflecting a world of weak economic growth and weak oil prices and the high-growth forecast representing a robust economy and oil prices.

CERA concedes its findings come at a difficult time when most major oil sands projects have been cancelled, postponed or reduced in size because of the slump in oil prices and uncertainty over the duration of the economic downturn that Yergin said "really does come at a critical juncture for the future of the oil sands."

The study urged Canada and the United States to establish a joint approach in regulating greenhouse gas emissions to reduce market distortions and head off any trade conflicts.

It argued that the impact on climate change of oil sands operations might not be as severe as many critics suggest.

CERA said that although extracting and processing oil sands bitumen through combustion of its refined products emits more GHGs than the average barrel consumed in the United States, its "wells-to-wheels" analysis shows emissions are only 5-15 percent greater than the average barrel, because 70-80 percent of total carbon emissions from crude oil result from burning refined products such as gasoline.

The firm also called for governments to play a greater part in advancing new technologies to lower emissions, rather than placing their hopes on the costly and unproven carbon capture and storage method.

James Burkhard, study director and managing director of IHS CERA's Global Oil Group, said several new technologies in various stages of development could "significantly increase production and the efficiency of oil sands operations, but they must be proven effective and economic at scale."

—GARY PARK

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PRODUCTION

No oil has been spilled.

But to guard against the possibility of an environmental disaster, the oil in the Drift River terminal's storage tanks has largely been replaced by ballast in the form of water. And Cook Inlet Pipe Line, owner of both the terminal and the pipeline connecting the terminal to the western Cook Inlet oil facilities, plans to clean out the terminal tanks, an operation that could last for several months once the current eruption ends. So, with the possibility of the eruption continuing for months, restart of the impacted oil fields on the west side of Cook Inlet seems a long way off.

Cook Inlet Pipe Line is owned 50 percent by Chevron and 50 percent by Pacific Energy Resources, with Chevron as operator.

Pacific Energy, which in March filed for chapter 11 bankruptcy protection, operates the Redoubt Shoal and West McArthur River fields, fields which feed oil into the Cook Inlet pipeline and Drift River terminal via Pacific Energy's own production facilities. On April 24 the company reported that its facilities had enough storage capacity for about another 60 days of production from its two fields. And on May 19 the company confirmed to Petroleum News that its fields were still producing oil into storage.

Determining options

Allison Iverson, coordinator for Alaska's Petroleum Systems Integrity Office, told Petroleum News May 12 that Chevron has put together a team to determine options for the future export of oil from the west side of Cook Inlet and will present those options to state officials in due course.

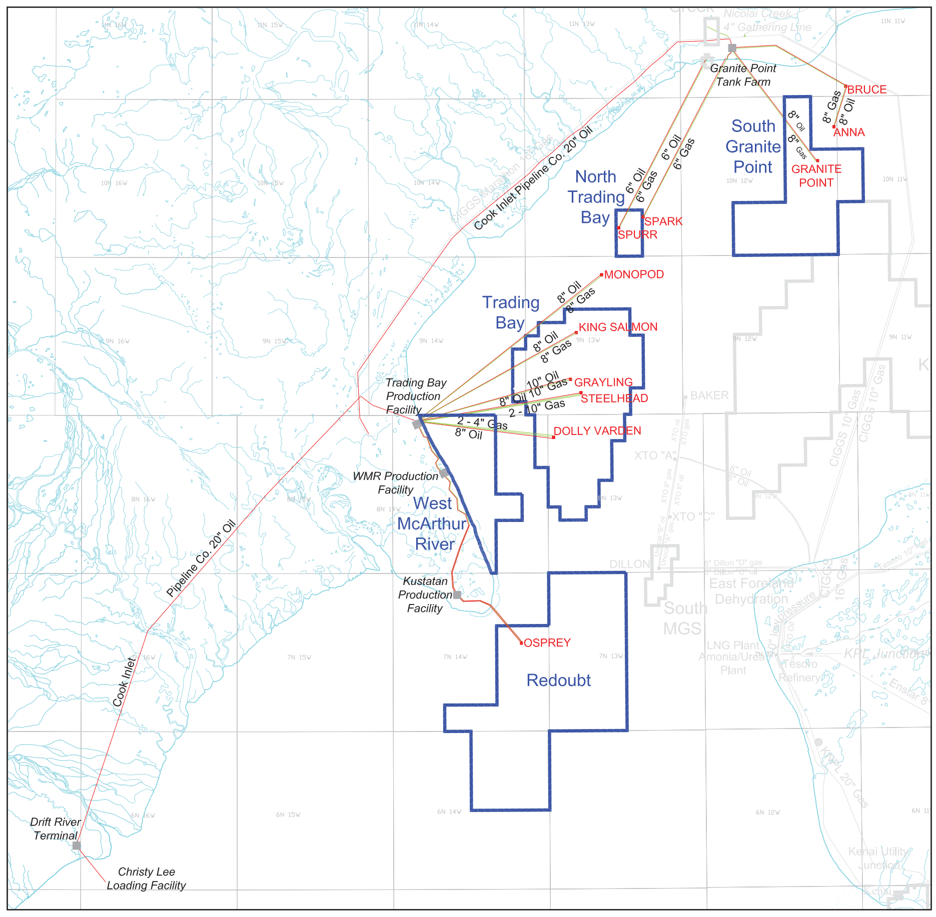
"They have told us that they are putting together an internal team to look at different potential configurations and different means of getting the oil across the Cook Inlet," Iverson said. "… When they're at the point of being able to move options forward, they will come to the state, and the state has committed to putting together a team to work with them."

In addition, there are regulatory requirements, including integrity tests, for restarting the terminal and the Cook Inlet pipeline — the U.S. Department of Transportation regulates both the pipeline and the tanks at the Drift River terminal, while the U.S. Coast Guard regulates the Drift River tanker loading dock, Iverson said.

But given the relatively low rates of remaining oil production from Cook Inlet oil fields, most which originally went into operation well over 30 years ago; given the environmental concerns associated with an oil terminal at the base of an active volcano; and given possible reservoir degradation resulting from a prolonged production hiatus, what are the long-term implications of the Drift River terminal shutdown?

Concern about reopening

"My concern is that we may very well see that Drift River does not reopen at all," David Carey, mayor of the Kenai Peninsula Borough told Petroleum News May 12. Carey characterized the oil and gas industry as "a major economic partner" with the borough in achieving a high quality of life for borough residents — the borough, with jurisdiction over the upper Cook Inlet, and over the Kenai Peninsula where many Cook Inlet oilfield workers live, has been anxiously participating in the response to Redoubt Volcano's threat to the Drift River terminal.



A map showing, outlined in blue, the oil fields on the west side of Cook Inlet that are impacted by the shutdown of the Drift River oil terminal. The field production facilities ship oil to the terminal through the Cook Inlet pipeline.

ALASKA DEPARTMENT OF NATURAL RESOURCES DIVISION OF OIL AND GAS

"People have been laid off in the past few weeks and almost every day we hear of another layoff," Carey said.

In addition to the direct impacts of layoffs on oil industry employees and contractors, the layoffs will have secondary impacts in terms of overall economic activity. Oil industry people buy or rent houses, buy food and contribute to the community in many ways, Carey said.

Reduced spending will also lead to a reduction in government revenues from sales taxes, he said.

Oil and gas industry property taxes, assessed by the state but paid to the borough, are also a major concern. This year the state increased its Kenai Peninsula Borough oil and gas property assessment from $603 million to $700 million, primarily because of some drilling rigs that are expected to come into the region, Carey said. A permanent shutdown of some oil facilities would knock a significant dent in that assessment, although the reduced tax take would not come into effect until after next year's state property tax assessment.

But the question of whether a permanent shutdown of oil production is likely revolves presumably around the economics of low production rates from aging fields, and around the extent to which these fields can recover from the current shut-in.

Low production rates

In March, according to AOGCC data, the Granite Point field and the Trading Bay field, two of the fields that were shut-in at the beginning of April, were producing oil at the rates of 2,554 barrels per day and 4,577 bpd. West McArthur River produced 8,310 barrels of oil during the whole of March, while during that same period Redoubt Shoal, a field that has in the past suffered from production problems resulting from a compartmented reservoir, produced 3,124 barrels.

By comparison, Division of Oil and Gas figures shown that in 1968 Granite Point production peaked at an average rate of 35,975 barrels per day, while in 1971 Trading Bay peaked at 18,395 bpd.

Chevron spokeswoman Roxanne Sinz told Petroleum News May 5 that several Cook Inlet oil fields had to be shut-in when Redoubt Volcano last erupted in 1989-90. At that time, the Granite Point field experienced a 10 percent production drop for about six months after a two-month shut-in; Trading Bay experienced a 5 percent drop for about four months after a four-month shut-in; and McArthur River, another Chevron-operated west Cook Inlet field, returned to pre-shut-in rates some three months after a two-month shut-in. However, the oil wells in the aging fields are not as robust today as they were nearly two decades ago, Sinz said.

"It is unclear how today's wells will respond to a return to production after a prolonged shut-in," Sinz said.

AOGCC Commissioner Cathy Foerster told Petroleum News that although declining pressure in the reservoir and increased water production can make production from older wells more difficult than that from newer wells to restore to full production after an extended shut-in, the specifics of how successfully each well can return to production depends on the individual characteristics of that well, characteristics that include water production rates, the local reservoir pressure, the dimensions of the well tubing and what, if any, artificial lift is being used to boost oil production.

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LEASE SALE

The three were part of a bidding group that took an onshore tract northwest of West Forelands in the state's 2006 Cook Inlet areawide lease sale.

Chevron applies to take tract out of PA

Cook Inlet tract 597 is completely surrounded by leases included in the Ivan River unit and Chevron has filed an application to exclude the five-acre tract from the participating area.

The April 15 application from Chevron is for revision of the Ivan River gas pool No. 1 participating area and for establishment of separate participating areas for the Tyonek and Sterling-Beluga formations.

A producing gas well was drilled at the field in 1966 and shut-in; the unit was approved in 1967 and was contracted in 1969 when the Ivan River gas pool No. 1 participating area was formed. Chevron said in its application that the participating area was "established on the basis of the known aerial extent of the Tyonek formation."

Based on well data and seismic interpretation, the Ivan River unit was expanded and the Gas Pool No. 1 PA was revised in 1978.

The Ivan River unit 44-36 well was spud and completed as a Sterling-Beluga producer in 1993.

Unocal had been the operator at Ivan River and when it merged with Chevron in 2005 Chevron legacy seismic data became available.

New well drilled recently

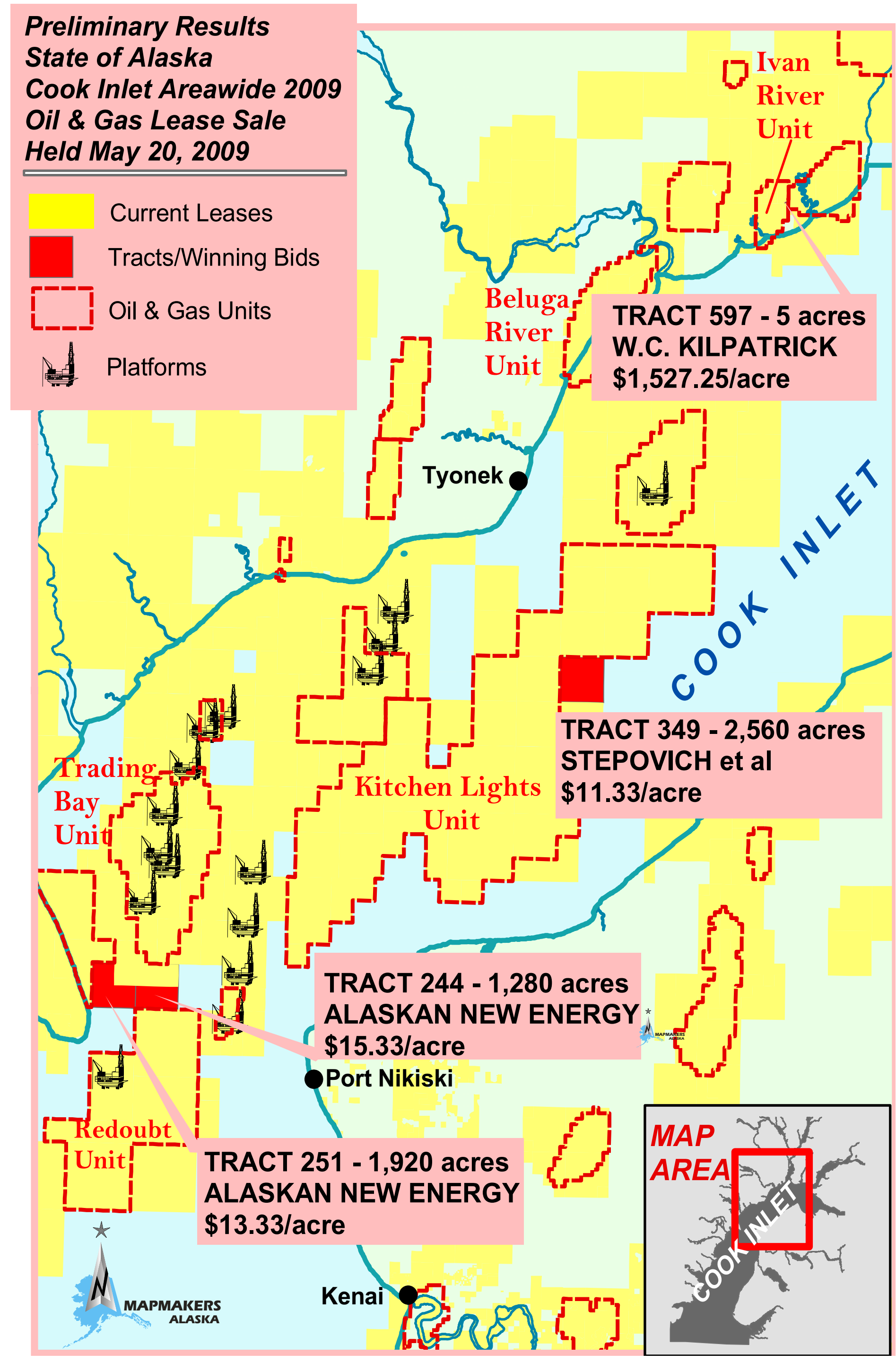
A new well was drilled this past winter, Chevron told the state, and data from that well along with previous seismic and well data allowed the company to outline separate participating areas for the Tyonek and Sterling-Beluga formations.

In its application Chevron said both the Ivan River unit agreement and state regulations require separate participating areas for separate pools or reservoirs, except where all unit owners agree to combined production. State regulations require separate participating areas for separate formations "except where there is consent by and among the commissioner and all working interest owners."

To date, production from separate formations in the Ivan River unit has been allocated to one common participating area, but the company said it "does not consent to this allocation methodology, and desires to establish separate participating areas for the Tyonek and Sterling-Beluga formations."

Chevron said creating separate participating areas is consistent with the approach the state took in a recent decision on the Stump Lake unit, when the state separated the Stump Lake gas pool No. 1 participating area into two participating areas, the Beluga and Sterling gas PA and the Tyonek gas PA.

—KRISTEN NELSON



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PRODUCTION

Dudley Platt, a petroleum engineering consultant with many years of Cook Inlet experience, told Petroleum News that the Hemlock formation, the main oil-bearing reservoir rock for the oil fields on the west side of Cook Inlet, tends to contain clay which is susceptible to swelling, a phenomenon that might tend to clog the reservoir when fluid stops flowing into the producing wells.

"When you shut-in anything, much like a salad dressing with vinegar and olive oil in it, once it settles out you've got the water over the (well) perfs and the oil floating on top, and the water may contribute to the swelling of the clays," Platt said.

To recapture production it may be necessary to flush out the wells, re-perforate the wells or treat the area of the perforations with acid, he said. In an extreme case, it might be necessary to re-drill wells.

Platform removal

If the worst were to happen, and some platforms were to permanently shut down, the field owners would at some point be faced with the expensive operation of dismantling and removing the offshore structures. However, although the terms of the state oil and gas leases require oilfield acreage to be returned to its original condition, to the satisfaction of the state, dismantlement of the Cook Inlet platforms is still a long way off, Nan Thompson, units manager in Alaska's Division of Oil and Gas, told Petroleum News May 12.

"They have to determine that there's nothing else producible (before dismantlement)," Thompson said.

Thompson said that the state does not currently have regulations for platform removal, but that the division is currently working on this issue.

And maybe further use could be made of platforms, even after the original fields have stopped producing: Dan Seamount, a commissioner with the Alaska Oil and Gas Conservation Commission, has in the past suggested that the aging Cook Inlet platforms might find a use in exploratory drilling for new oil and gas resources.

One factor that might also play into all of this would be the economics of scale achievable by waiting to remove several platforms in one large project, rather than bringing a barge and other expensive equipment to the state to just remove a single structure — it is likely to be cheaper to mothball, or "lighthouse," a single platform that is no longer in use, than to dismantle it, Platt said. ●