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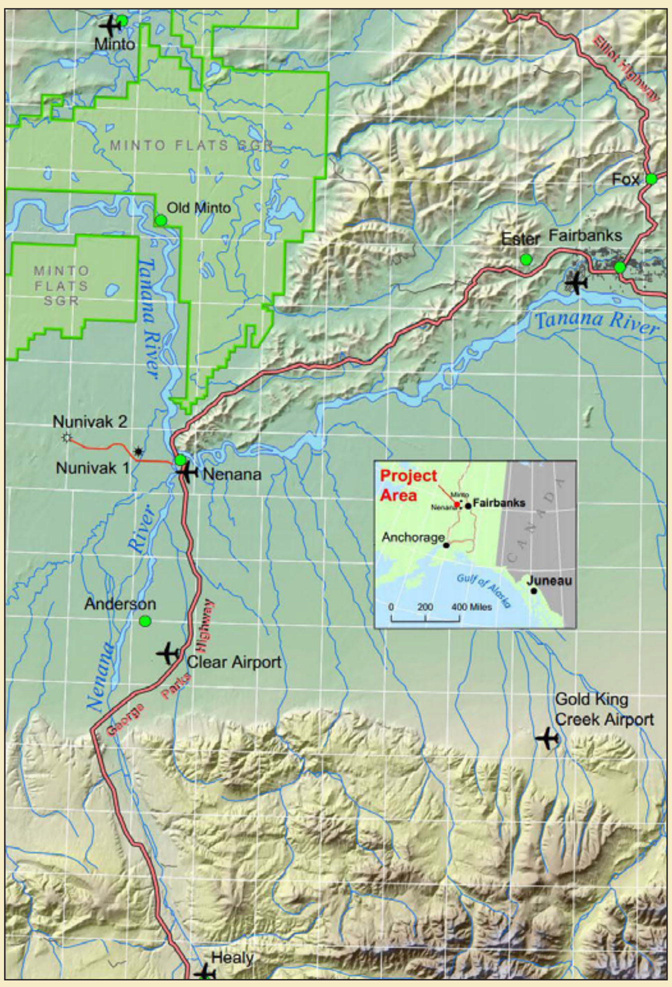
page 10 Governor includes $355 million for Fairbanks LNG in budget



COURTESY DOYON

Doyon files plan for Nunivak #2 well in Alaska's Nenana basin

Doyon Ltd., the Native regional corporation for Alaska's interior, has filed a plan of operations for its Nunivak No. 2 exploration well, in the Nenana basin 50 miles or so southwest of Fairbanks. The plan, filed with Alaska's Division of Oil and Gas, says that the corporation anticipates drilling the well between June and August 2013, with construction of the well pad and an access road taking place over the winter.

Gas exploration

For several years Doyon has been exploring for gas in the Nenana basin, a large depression in the Earth's crust filled with river- and lake-borne sediments, primarily of Tertiary age. The proximity of the basin to the road, rail and power transmission line corridor between Anchorage and Fairbanks makes the potential of a gas find in Nenana particularly

see **DOYON WELL** *page 18*

NWT minister hopes for Beaufort app by summer; Imperial mum

Northwest Territories Industry Minister Dave Ramsay has fired the starting gun for a return to drilling in the Canadian Beaufort, but lead player Imperial Oil has remained in the starting blocks, mulling its next move.

After mixing and mingling with industry decision-makers at the Arctic Technology Conference in Houston, Ramsay felt confident enough to predict that the partnership of Imperial, ExxonMobil and BP is "very optimistic about moving things forward ... sooner rather than later," and might be ready to submit a regulatory application in summer 2013.

Imperial spokesman Pius Rolheiser was much more circumspect, telling Petroleum News his company was not ready to confirm it intends to shrug off years of inactivity in the region and move to the drilling stage.

"We continue to assess options and develop plans for potential further exploration activities," he said.

see **CANADIAN BEAUFORT** *page 17*

FINANCE & ECONOMY

AIDEA funds Mustang road

With $20M loan, public corporation will help build early infrastructure

By ERIC LIDJI
For Petroleum News

In a move described as a sign of things to come, the Alaska Industrial Development and Export Authority has agreed to loan $20 million to a small independent looking to build road and pad infrastructure to support a budding North Slope oil field development.

The $20 million purchases an 80 percent stake in Mustang Road LLC, a new company the public corporation will create with Brooks Range Petroleum Corp. The company will fund the initial infrastructure needed to bring the Mustang field into production by 2014.

The field is in the Brooks Range Petroleum-operated Southern Miluveach unit, located in the central North Slope, adjacent to the southwestern corner of the Kuparuk River unit.

While AIDEA hopes to create a model it can replicate in the future, it also believes the Mustang road will improve the economics for other development projects in its vicinity.

By financing one small piece of a development project with the goal of improving the overall economics of the entire project, the Mustang Road deal "breaks new ground for the authority," AIDEA board member Robert Sheldon said during a meeting Dec. 6.

see **MUSTANG ROAD** *page 18*

FINANCE & ECONOMY

Oil to remain top dog

ExxonMobil also predicts bright future for natural gas in annual energy outlook

By WESLEY LOY
For Petroleum News

While natural gas and renewables are surging, oil will remain the globe's No. 1 fuel for the foreseeable future. And the world still has a treasure trove of oil to extract, ExxonMobil says in its latest "Outlook for Energy" report.

The annual report makes predictions out nearly three decades, to the year 2040.

"Even by 2040, ExxonMobil estimates that less than half of the world's recoverable crude and condensate will have been produced," the report says. "Even with production, the resource base continues to grow due to the ability of the industry to find and develop new types of resources through improved science and technical innovations."

The report, released on Dec. 11, is a sweeping overview of the world energy mix, with observations on population and development trends, electricity generation, energy trading, energy efficiency and air pollution.

"Overall, global energy demand will grow 35 percent, even with significant efficiency gains, as the world's population expands from about 7 billion people today to nearly 9 billion people by 2040, led by growth in Africa and India," the report says.

Liquids outlook

The energy outlook details the changing char-

see **ENERGY OUTLOOK** *page 20*

EXPLORATION & PRODUCTION

Engineering & know-how

Barnes describes how Hilcorp is re-invigorating its fields in Cook Inlet basin

By ALAN BAILEY
Petroleum News

JOHN BARNES

Hilcorp Energy's oil and gas development program in Alaska's Cook Inlet basin slots into the company's objective to double in size between 2011 and 2015, John Barnes, Hilcorp Alaska's senior vice president, exploration and production, told Commonwealth North's Energy Action Coalition on Dec. 7. Since acquiring Chevron's Cook Inlet assets at the beginning of this year, the company has been moving forward with aggressive plans to breathe new life into the aging oil and gas fields of the basin. The company is also in the process of purchasing Marathon Oil Co.'s Cook Inlet assets.

Aging assets

The company's mode of operation is to invest significant capital into the aging assets that it acquires, to grow the company by boosting production and reserves. And the company is spending a significant amount of money in the Cook Inlet basin, as it tries to turn around the sagging fortunes of fields, most of which first came on line several decades ago.

"We've got the cash flow to do that and really drive the assets where we want to go," Barnes said.

Hilcorp places particular emphasis on top-notch

see **HILCORP PROGRAM** *page 19*

contents

Petroleum News *North America's source for oil and gas news*

Alaska - Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay AGI-05	BP
Dreco 1000 UE	16 (SCR/TD)	Milne Point MPF-54	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD1-47	ConocoPhillips
AC Mobile	25	Prudhoe Bay Y-19A	BP
OIME 2000	141 (SCR/TD)	Kuparuk 2A-27	ConocoPhillips
Kuukpik	5	Mobilizing to Umiat	Linc Energy Operations Inc.
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Prudhoe Bay	Stacked
AC Coil Hybrid	CDR-2	Kuparuk 1R-29	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay	Available
Mid-Continental U36A	3-S	Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay	Available
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay	Committed
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist -2	18-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist	28-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Prudhoe Bay*	Available
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC electric Canrig	105-E (SCR-TD)	Prudhoe Bay	Commiitted

*Pioneer winter work

Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site D-31A	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site Z-07A	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 3M-14	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay final construction and commission	BP
NOV ADS-10SD	273	Prudhoe Bay, Mobilized to BP first location Dec. 8th	BP

North Slope - Offshore

BP			
Top drive, supersized	Liberty rig	Inactive	BP
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-24	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point	ENI
Doyon Drilling			
Sky Top Brewster NE-12	15 (SCR/TD)	Spy Island SI13-FN4	ENI

Cook Inlet Basin – Onshore

Kenai Land Ventures LLC (All American Consultants, labor Contract)			
Taylor	Glacier 1	Kenai Loop Drilling Pad #1	Buccaneer Energy Ltd
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Happy Valley drilling HV B-16	Hilcorp Alaska LLC
Cook Inlet Energy			
Atlas Copco RD20	34	Finalizing Otter Project west side of Beluga River Field	Cook Inlet Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Swanson River 14B-27	Hilcorp Alaska LLC
Nabors Alaska Drilling			
	99AC	North Fork 22-35	Armstrong Cook Inlet, LLC
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Stacked in Kenai	Available
Rigmaster 850	129	Kenai	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Tiger Eye 1	NordAq

Cook Inlet Basin – Offshore

XTO Energy			
National 110	C (TD)	Idle	XTO
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Furie
Cook Inlet Energy			
National 1320	35	Osprey Platform RU-1, workover	Cook Inlet Energy
Hilcorp Alaska LLC (Kuukpik, labor contract)			
		Steelhead Platform Well M-31, redrill, KD management Contract	Hilcorp Alaska LLC
	428	Anna Platform, preparing rig for drilling, KD Providing Labor	Hilcorp Alaska LLC

Mackenzie Rig Status

Canadian Beaufort Sea

SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

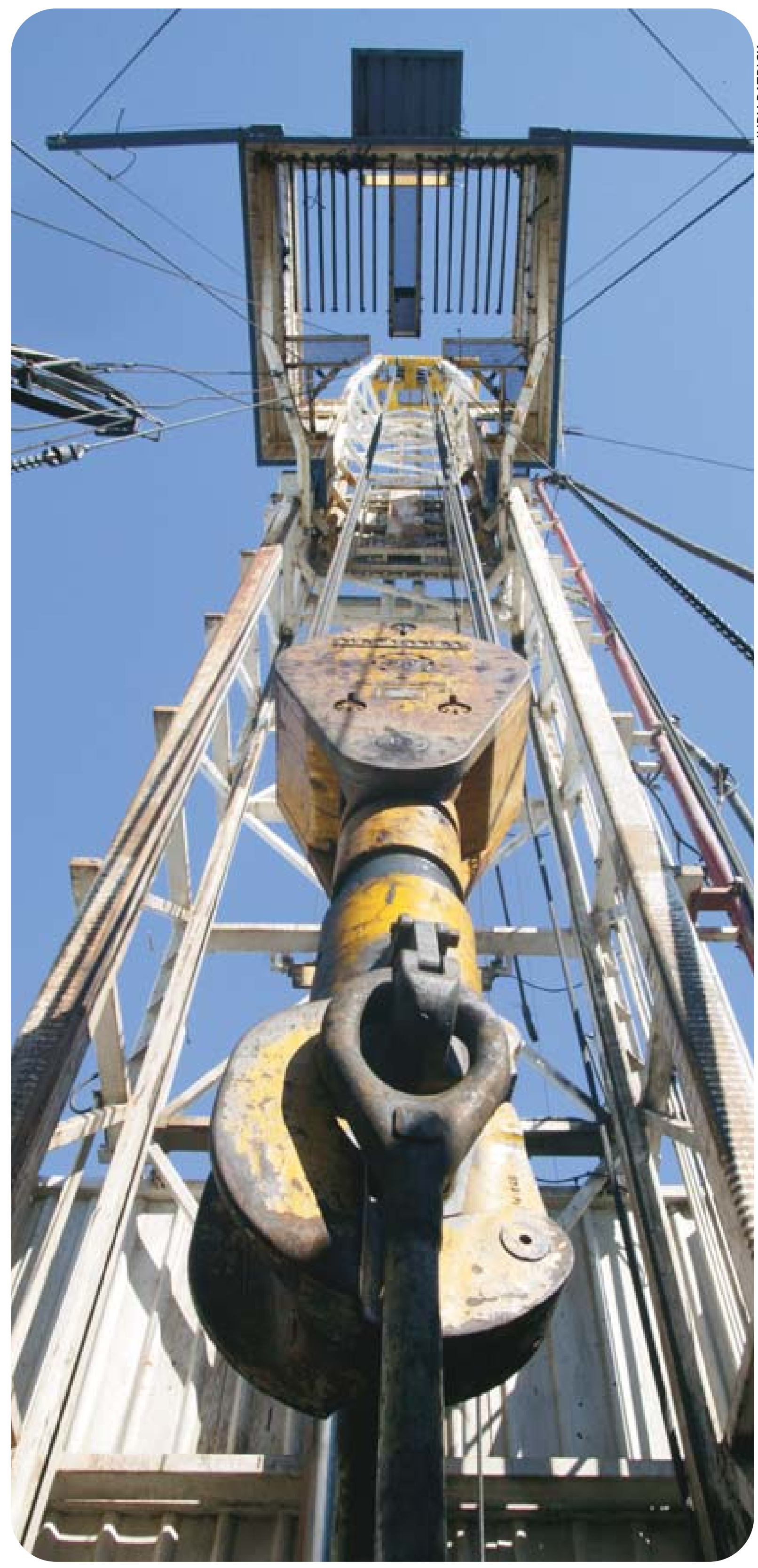
Central Mackenzie Valley

Akita/SAHTU			
Oilwell 500	51	Still out of the NWT, but is again available	Available

The Alaska - Mackenzie Rig Report as of December 13, 2012. Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Dec. 7	Nov. 30	Year Ago
US	1,800	1,811	1,987
Canada	406	399	504
Gulf	48	48	39

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

*Issued by Baker Hughes since 1944

The Alaska - Mackenzie Rig Report is sponsored by:

XTO ENERGY

● NATURAL GAS

An uncertain LNG future for Alaska

The export of North Slope gas as LNG faces uncertainty over future market conditions and over competition from other producers

By ALAN BAILEY
Petroleum News

In a talk during the Law Seminars International's annual Energy in Alaska conference in 2011, Paul Carpenter, chairman and principal of the Battle Group, said that major uncertainty over future gas market conditions has for many years formed a road block to moving forward with a major project to build a gas line from the North Slope to the Lower 48.

On Dec. 3, during this year's conference, Carpenter turned his attention to the prospect of exporting Alaska gas as liquefied natural gas, or LNG.

The shale gas revolution and low gas prices in North America have driven an interest in exporting LNG to the Pacific Rim, where LNG currently commands relatively high prices. Exxon, ConocoPhillips, BP and TransCanada, with encouragement from the State of Alaska, have turned their attention to a potential LNG export project, involving a gas line to an LNG facility at tidewater in Southcentral Alaska. The producers have estimated the total project cost, including the liquefaction plant and a gas treatment plant on the North Slope, to be somewhere in the range $45 billion to $65 billion, and possibly more, Carpenter said.

High cost

Although it might be tempting to think that the fact that the North Slope gas is currently stranded makes an LNG export project a "no brainer," this is far from the case, given the high cost of the project, Carpenter cautioned.

"While the gas may be cheap at the source, the infrastructure that's required to bring it to market is not," Carpenter said. And, given the lead time required to bring an LNG export project to fruition, exports would not begin until after 2020, he said.

So, what are the uncertainties that might give a would-be LNG exporter from Alaska pause for thought before parting with multiple billions of dollars in capital investment?

The export to Asia of U.S. LNG from the Gulf Coast may be impeded by high tariffs on the Panama Canal, even although the canal is being widened to handle LNG carriers, Carpenter said.

Two scenarios

The International Energy Agency's most recent World Energy Outlook report put forward two gas market scenarios that represent two end points of a spectrum of future market possibilities, Carpenter said. One scenario, referred to as "the golden rules case" posits that the shale gas revolution will continue, with the use of shale gas technology spreading widely around the world. The other scenario, "the low unconventional case," assumes that the spread of shale gas development would be stunted as a consequence of issues such as environmental concerns or development problems.

"I would tend to think that the golden rules case would be the kind of thing that might be more likely to occur, in the sense that it's hard to stop technology from spreading around the world," Carpenter said, observing that the low unconventional case might bode better for the prospects of Alaska LNG exports.

On the other hand, there have been reported problems with the international spread of shale gas technology: In China, for example, much of the shale gas resource is in populated areas, or in desert areas that lack the water needed for shale gas production.

India and China

The International Energy Agency's forecasts of future LNG import needs point to India and China as dictating future demand growth, Carpenter said. The agency forecasts about 10 billion cubic feet per day of incremental demand from these countries between 2010 and 2020, an incremental demand that roughly matches the incremental LNG exports that Australia has committed to between

see LNG FUTURE page 8

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● GOVERNMENT

Now you see it, now you don't

Canada ends open season for foreign state-owned enterprises to seize control of oil sands; approves CNOOC, Petronas takeovers

By GARY PARK
For Petroleum News

The Canadian government left the door open long enough to allow China's CNOOC and Malaysia's Petronas to sneak through and gain regulatory approval for their respective takeovers of Nexen and Progress Energy Resources.

At the same time, Prime Minister Stephen Harper slammed the same door on any future attempts by state-owned enterprises, SOEs, to take control of oil sands companies in particular, other than in "exceptional circumstances."


STEPHEN HARPER

In changing Investment Canada Act rules governing foreign investments in Canada's natural resources sector, the Harper administration failed to satisfy either side after taking four months to bring what was supposed to be clarity and consistency to a controversial issue.

But Industry Minister Christian Paradis, who oversees foreign investment reviews, said Canada could not afford to apply the new rules retroactively.

"We have a hard-won reputation," he said. "Canada is a stable place. We are serious in terms of predictability."

In other words, in recalibrating its investment dealings with Beijing, the Harper government did not want to start out by rebuffing CNOOC and possibly future billions of dollars of investment in the petroleum industry.

Diverging opinions

Whether it has succeeded is already the subject of diverging opinions.

Some say a new bilateral investment rights treaty is designed to guarantee fair treatment of Chinese and Canadian investors doing business in the other nation.

"That's essentially the big gift for China," said Stuart Trew, trade campaigner for the nationalist Council of Canadians. "That's the deal that's going to let the CNOOCs of the world, or other Chinese investors, expand without limit."

Alberta Premier Alison Redford applauded the approval of the US$15.1 billion Nexen transaction, which gives CNOOC assets in the oil sands and British Columbia shale plays along with the Gulf of Mexico, North Sea and offshore West Africa, and the C$6 billion Petronas offer for major natural gas prospects held by Progress with the prospect of using those resources for an LNG export venture.

Still unclear is how the United States government will react to the future of Nexen's operations in the Gulf of Mexico.

But Redford was less effusive in announcing that her government would "study the implications of (Harper's) statements about future investments by state-owned enterprises."

Alberta Intergovernmental Affairs Minister Cal Dallas said Alberta plans to reach out as a stakeholder once it understands the implications of the new guidelines.

"What's clear is we will continue to need to attract large amounts of capital into Alberta and into Canada to support the development of the oil sands," he said. "We will have to first see exactly what the language of the policy means."

Dallas, while doubting there would be a "massive negative reaction" from Chinese investors, was more concerned about the impact on the valuation of other oil sands players.

Estimated C$17B on market

Calgary-based investment dealer Peters & Co. has estimated that oil sands assets worth C$17 billion are currently on the market, including various stakes held by ConocoPhillips, Marathon Oil and Murphy, matching the combined value of oil sands transactions over the past decade.

For Paradis the message behind the new guidelines is clear.

Canada is open to allowing state-owned enterprises to gain minority stakes in oil sands companies, or to negotiate joint ventures, he said, but added his government is not prepared to allow a wave of buyouts of oil sands producers by Chinese state-owned corporations or other energy-hungry countries.

Harper told reporters that with only 15 companies playing leading roles in the oil sands his government was concerned that further control by SOEs would not be beneficial for Canada.

"When we say that Canada is open for business, we do not mean that Canada is for sale to foreign governments," he said.

"The government's concern and discomfort for some time has been that very quickly, a series of large-scale controlling transactions by foreign state-owned companies could rapidly transform (the oil sands) industry from one that is essentially free market to one that is under the control of a foreign government."

He said the CNOOC acquisition of Nexen's oil sands assets — primarily its controlling stake in the financially and operationally challenged Long Lake project — was "not the beginning of a trend, but the end."

SOE threshold remains C$330M

Included in the government changes, the threshold triggering a review of takeovers by foreign private investors will be raised to C$1 billion from C$330 million, but C$330 million will remain in place for SOEs.

The government also set out five conditions SOEs must meet in future to gain government approval for a transaction, including proof that an investment would be commercially oriented and that the investor would be free from influence by its home government.

What Canada described as its "net benefit test" will remain in place for all takeovers, whether by private companies or SOEs, while a second phase of tests will be applied to determine how much control or influence the SOE would have over a Canadian subsidiary and how much control or influence the foreign government would have over the subsidiary.

In the immediate run up to the announcement, the jittery mood among Nexen and Progress investors was evident as shares of Nexen tumbled as much as 16 percent on the Toronto Stock Exchange, triggering a circuit breaker that briefly halted trading in the stock, while Progress shares slipped 4 percent.

Just days before it obtained the go-ahead to complete its takeover of Progress, Petronas said that approval would trigger massive investment in a joint LNG export project in British Columbia. Initial plans for the Pacific Northwest LNG project involve processing 2 billion cubic feet per day of gas for export.

"It shows Petronas and Progress have confidence there is a viable LNG industry in Canada," Progress Chief Executive Officer Michael Culbert said.

"A decision like (the Petronas deal) that allows foreign investment, whether it comes through joint ventures or equity, is critical for Canada to go forward and be competitive in the world LNG markets."

Companies disagree

Sveinung Svarte, chief executive officer of Athabasca Oil Corp., which has reportedly been attempting to negotiate a minority deal with state-owned Kuwait Petroleum Corp., said the new rules "look positive" from the standpoint of joint ventures.

But John Brussa, chairman of Penn West Petroleum, which is working with Japanese utilities and Korea Gas on a possible plan to export LNG, said the news is not very positive for shareholders who will no longer be able to collect the premiums that come with takeovers.

Laura Lau, senior vice president and portfolio manager at Brampton Investments in Toronto, expects valuations of Canadian resource companies will now fall because of the chill in the investment atmosphere.

The law firm of Stikeman Elliott said the new SOE guidelines "may impede escalated SOE participation in (the oil and gas sector), with a resultant drag on the speed and degree of such development."

Murray Edwards, chairman of Canadian Natural Resources, one of the most influential voices in the Canadian petroleum industry and someone who reportedly has the ear of Harper, recently told reporters that Canada should not allow a strong domestic presence in the oil and natural gas sector to erode.

"There is a desire, if not a need, to make sure we have strong Canadian champions in industry, as well as strong foreign capital," he said.

Edwards said the government needed to impose some strict conditions or limitations on takeovers or Nexen would just be the first of many companies to disappear.

Peters & Co. said the high level of assets potentially available for buyers "results from the cost intensive nature of developing these assets, combined with lower netbacks compared to other crude oil plays in North America."

"While on a near-term basis this may provide operators with more flexible opportunities to deploy capital, we believe the scale and production potential of the oil sands will continue to attract capital from large foreign companies wanting to secure significant resource," it said. ●

Contact Gary Park through publisher@petroleumnews.com

GOVERNMENT

Election has energy ramifications

Lawyer says Obama's strong position will likely lead to more climate change related regulation, but US economy is priority

By ALAN BAILEY
Petroleum News

The failure of the Republican Party to capture a majority in the U.S. Senate was the biggest surprise in the recent election, Craig Gannett, a partner with Davis Wright Tremaine, told Law Seminars International's Energy in Alaska conference on Dec. 4. Gannett is a lawyer with extensive experience in issues relating to climate change and energy.

"That surprise ripples through everything else that's going to go on in D.C. for at least the next two years," Gannett said.

Strong position

The Senate, under Democratic control, can kill any legislation that the Republican House of Representatives sends it. As a consequence, no legislation will reach President Obama that the president doesn't essentially support, thus placing the president in a relatively strong position, Gannett said.

One outcome of Hurricane Sandy has been a new awareness of the vulnerability of the U.S. energy infrastructure, in particular the energy transportation infrastructure such as pipelines, Gannett said.

"My sense is that Obama's second term is going to be relatively energetic and relatively effective," he said.

Having achieved two of his three prime objectives for his first term in office — the enactment of legislation relating to financial reform and health care — the president still has climate change, his third objective, in view, even although this topic saw no mention during the presidential campaign, Gannett said. Federal energy policy is likely to increasingly become synonymous with climate change policy, with climate change concerns suffusing and undergirding many policy initiatives, he said. The impact of Hurricane Sandy and predictions by scientists of an increasing frequency of extreme storms is re-enforcing those concerns.

But people should not anticipate the president introducing any major new bills during his second term.

"He has plenty of existing law to implement in the next four years without any need for significant change," Gannett said.

Policy through regulation

Instead, having that Senate protection from any challenge on the legislative front, the president will likely implement climate change policies by regulation through existing laws, Gannett said. Gannett cited new emissions controls for ships operating within 200 miles of the U.S. coastline as an example of the type of highly technical regulatory initiative that federal agencies could introduce.

However, with the nation's economic challenges taking top position in the government's priority list, there is unlikely to be a flood of new agency regulations in the near future.

"The economy will remain the focus until it returns to something more robust and that may well take the entire four years," Gannett said.

On the other hand, with the Supreme Court having ruled that the administration can regulate greenhouse gases as pollutants, the Environmental Protection Agency is in a strong position to, for example, require best available control technology for power plants, thus creating difficulties for coal-fired plants and placing any form of greenhouse-gas-free energy at a premium.

"All renewables are well positioned in this environment," Gannett said.

No easy answers

Asked how he though the Obama administration might reconcile the need for economic growth with the likely increase in energy prices as a consequence of climate-change-related measures, Gannett responded that climate change is a complex and emotive issue with no easy answers.

"It may cause higher prices, but you have to offset that against the long-term environmental impacts that the vast majority of scientists seem to think that we're facing," Gannett said. "That's a causal connection that I think the administration largely accepts."

And renewable energy technologies, which some people think provide new job creation opportunities, were closing the energy cost gap before the emergence of fracking technologies for oil and gas production had "thrown the cards up in the air," he said.

One outcome of Hurricane Sandy has been a new awareness of the vulnerability of the U.S. energy infrastructure, in particular the energy transportation infrastructure such as pipelines, Gannett said. This is a trillion dollar issue that the administration will need to face, he said.

Action to watch

From the perspective of Alaska, the action to watch will be in the Senate Energy and Natural Resources Committee, where Sen. Ron Wyden, D-Ore., will be the new chair and Sen. Lisa Murkowski, R-Alaska, will be ranking member, Gannett said.

"The working relationship between Wyden and Murkowski is going to be critical and I have every reason to think it's going to be a good working relationship," he said. One issue that this committee will need to address is the question of exporting liquefied natural gas from the United States, with Wyden and Murkowski having radically different perspectives on this question.

One person to keep an eye on is Sen. Patty Murray, D-Wash., a "rock star" in the Democratic caucus who will chair the Budget Committee, Gannett said. Hopefully there will be a strong relationship between Murray and the Alaska delegation over a wide range of issues, he said.

In the administration, there may be some cabinet changes of particular interest to Alaska. It is not clear whether Secretary of the Interior Ken Salazar will remain in office, but Energy Secretary Steven Chu is a more likely departure. Gannett said that he had heard that Jane Lubchenco, the administrator of the National Oceanic and Atmospheric Administration, is likely to leave.

The current term of Chairman Wellinghoff of the Federal Energy Regulatory Agency ends in June, but with the possibility of Wellinghoff remaining in office until the end of 2013. ●

Contact Alan Bailey at abailey@petroleumnews.com

● LAND & LEASING

Independents propose Badami expansion

Savant and Alaska Venture Capital Group ask state to expand eastern North Slope unit to include East Mikkelsen prospect

By ERIC LIDJI

For Petroleum News

Savant Alaska LLC is asking the state to add seven leases to its Badami unit, including six held by Alaska Venture Capital Group LLC, bordering the eastern North Slope unit.

The leases would add some 10,121 acres by bringing the East Mikkelsen prospect into the unit, expanding the total area of the Badami unit to some 33,702 acres and 16 leases.

Through its operating arm Brooks Range Petroleum Corp., AVCG originally included its six leases in the Telemark unit, a nine-lease unit the small independent proposed for the fairway between the Badami and Point Thomson units. Because the East Mikkelsen prospect underlay both Brooks Range Petroleum and Savant acreage, the companies decided the best way to development the prospect would be to expand the existing unit, Brooks Range Petroleum Chief Operating Office Bart Armfield told Petroleum News.

With the expansion, Savant would drill an exploration well in the expansion area in the 2014 winter drilling season. The directional well would test an equivalent of the hydrocarbon-bearing Killian sand that Humble Oil encountered in the East Mikkelsen Bay No. 1 well in 1971. The well flowed at a rate of 700 barrels of 24 API oil per day.

The project "would be structured to allow the well to test a shared prospect between Savant and BRPC, as well as allow for a sidetrack well to test a prospect which was formerly within the existing Badami Unit controlled by Savant," Armfield wrote.

Savant believes the expansion leases "connect subsurface potential and surface infrastructure" for the two companies in the region. By combining the leases into a single unit, "drilling targets could be reached more easily and development could occur more efficiently and safely with less environmental impact on the area," according to Savant.

The Alaska Venture Capital Group leases are ADL 390825, ADL 391284, ADL 391285, ADL 391001, ADL 391376 and ADL 391378. The Savant lease is ADL 391431.

With approval of the expansion, the three additional leases Brooks Range Petroleum proposed for the Telemark unit, northeast of Badami, would retroactively expire.

The state is taking comments on the proposal through Jan. 14.

In the summer of 2011, Brooks Range Petroleum applied to form the 200,058-acre Greater Bullen unit over 68 state leases in a similar area of the eastern North Slope, but withdrew the application and relinquished some 100,000 acres a few months later.

The proposal included plans for six wells between 2012 and 2020 with production expected to begin in mid-2015, plus a 300 square mile 3-D seismic survey by early 2012.

The proposed unit included the Friezen and Red Dog prospect. Friezen was the main prospect of the former BP-operated Slugger. BP estimated the unit contained some 280 million barrels of oil, but never publically estimated the recoverable reserves for the unit. Estimates for Red Dog range from 45 million to 85 million barrels of recoverable oil.

In early 2012, Brooks Range Petroleum proposed the Telemark unit from the nine leases included in the "N" block, one of six exploration blocks proposed for Greater Bullen.

In its Telemark proposal, Brooks Range Petroleum planned to shoot a 3-D seismic survey by the end of 2012, choose a drilling location in 2013 and drill a well by March 2014. ●

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FINANCE & ECONOMY

Making a trillion-dollar case

The Canadian petroleum industry has a vital sales job to perform to win over opponents of oil sands development, says Geoff Hill, national oil and gas leader and a partner in the firm of Deloitte.

Speaking at an event sponsored by Fluor Canada, he argued that even though Canadians are passionate about the oil sands from different angles, "some of the obstacles can be turned into opportunities" because of that passion.

But, for now, Canadians are rather illiterate about energy issues, especially when it comes to making a connection between the industry and the economy, Hill said.

To overcome that he called for a comprehensive approach to energy education, starting with the public kindergarten-to-Grade 12 system, to address issues of consumer literacy and national unity.

Based on a recently released Deloitte report, the oil sands could generate C$2.1 trillion in economic benefits by 2025, C$783 billion in tax revenue and 905,000 jobs, Hill said.

He questioned whether any other industry could provide the same amount of prosperity, making it incumbent on the industry to demonstrate that without oil sands development Canada's standard of living will not improve to the extent it could.

In order to achieve fair value for its oil sands production, it is important to diversify export markets beyond the United States, he said, noting Canada is "losing almost C$30 million a day because we are discounted by the supply-and-demand issue."

Hill said both large independents and small juniors are necessary to attract investment for oil sands development, suggesting that although only large companies can tackle major projects such as pipelines they depend on the tenacity and ingenuity of smaller companies to help propel the industry forward.

On the flip side, he said Canadians should take a strategic approach to maximizing value from the oil sands resource before exporting it outside North America, including the provision of domestic refining capacity.

Hill also urged greater collaboration within the industry and a national energy strategy to achieve greater national agreement on developing the resources.

"I don't think we need to be scared of working together," he said. "We need to be scared of not working together."

—GARY PARK

FINANCE & ECONOMY

Parker activates one arctic drill rig

Parker Drilling Co. has finally put one of its new Arctic Alaska Drilling Unit rigs to work on the North Slope.

Rig 273 has commenced drilling operations under terms of a five-year contract with BP, Parker said in a Dec. 12 press release.

"These are exciting times for our team," said Gary Rich, Parker chief executive. "True to our heritage of ingenuity and determination, our team is successfully conquering the challenges of developing technological advances and high-performance resources for harsh arctic environments. We thank BP for working with us to ensure these AADU rigs meet our shared performance objectives for safety and efficiency and we look forward to continuing to work with BP to unlock the full potential of this promising region."

Parker-built rigs 272 and 273 arrived on the North Slope about 16 months ago, in August 2011. Parker described them as a new and highly advanced class of drilling rig.

For reasons that remain somewhat mysterious, however, the rigs didn't proceed to work.

In January, Parker disclosed that BP was holding it in default under a drilling contract for failure to supply "operationally ready" rigs by Dec. 31, 2011. Parker disagreed that a default had occurred.

In an August filing with the U.S. Securities and Exchange Commission, Parker said it and BP had amended the contract with respect to "new deadlines for commencement of operations."

The second rig, 272, "remains on schedule for acceptance testing in 2013," Parker's Dec. 12 press release said.

Houston-based Parker is re-entering the Alaska market after an absence of several years.

Rig 273 has moved to Drill Site 2 in the BP-operated Prudhoe Bay oil field, Dawn Patience, spokeswoman for BP Exploration (Alaska) Inc., told Petroleum News on Dec. 12.

Patience provided this statement on Parker's announcement that rig 273 had commenced drilling operations:

"Under Alaska's current investment climate, BP needs to focus on opportunities that can improve our near-term Alaska business. Adding the Parker Drilling rig to our fleet advances efforts to accelerate light oil development at Prudhoe Bay and Milne Point."

Another BP spokesperson said in August 2011 that the Parker rigs were part of BP's effort to modernize its North Slope drilling fleet. The spokesman said the new rigs didn't signify a drilling expansion for BP. Rather, they would replace aging rigs.

—WESLEY LOY

continued from page 4

LNG FUTURE

now and 2017, he said. Australia has several LNG projects in progress.

That leaves about another 11 billion cubic feet per day of potential demand from China and India between 2020 and 2035, according to the International Energy Agency. A Brookings Institution study found that new LNG supplies will meet incremental demand increases between 2010 and 2020, with about 5 billion cubic feet per day of unmet demand after that. However, China will have opportunities to import pipeline gas from Russia and Eastern Europe, Carpenter said.

China is going to be the important uncertainty in the market, he said.

Supply competition

On the supply side of the demand and supply market equation, the potential Alaska project would deliver 3 billion to 3.5 billion cubic feet of gas per day as LNG. The Australian projects coming on line by 2017 would in total be equivalent to about three times the Alaska production, and worldwide there are many other LNG export projects that have been proposed, including exports from the U.S. Gulf Coast and from British Columbia. In total there is the equivalent of about 13 Alaska-sized projects potentially coming on line ahead of Alaska, with consultancy firm Wood Mackenzie suggesting that the sweet spot for the timing of new LNG exports will be around 2016 to 2018.

"Basically the timing of this competition doesn't favor Alaska," Carpenter said.

And long-term contracts, many of them 15 to 20 years in duration, have been signed for LNG projects already under way.

"That's one of the advantages of being a first mover," Carpenter said. "Unfortunately this is not available to the Alaska project at the moment."

LNG prices

Then there is the question of the future price of LNG in world markets.

"This is a very difficult thing to predict," Carpenter said.

A supply glut by 2020, perhaps from shale gas production in target market areas or from the export of shale gas from North America, could depress Asian prices. On the other hand it is unclear to what extent the U.S. Department of Energy will approve LNG exports from the Lower 48, given the pressure to restrict U.S. exports. And the Australian projects are facing significant cost pressures because of a shortage of skilled staff for multiple projects being conducted simultaneously, Carpenter said.

The export to Asia of U.S. LNG from the Gulf Coast may be impeded by high tariffs on the Panama Canal, even although the canal is being widened to handle LNG carriers, Carpenter said.

Current high LNG prices in Asia result from a tradition of linking LNG prices to the price of oil in LNG supply contracts. But LNG buyers, seeing the multitude of shale gas projects being developed in North America, are questioning that oil price linkage. North American developers, on the other hand, want a continuation of the linkage and producers in western Canada say that oil-linked Asian prices are driving their LNG projects.

"Where this comes out obviously will be very important to the prospects for a post-2020 Alaska LNG project," Carpenter said. ●

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● FINANCE & ECONOMY

EIA projects US production at 6.4M bpd

Agency says 2012 estimate an increase of 800,000 bpd from 2011, expected to increase to 7.1 million bpd in 2013, highest since '92

By KRISTEN NELSON
Petroleum News

U.S. total crude oil production is expected to average 6.4 million barrels per day this year, the U.S. Energy Information Administration said in its latest Short-Term Energy Outlook, released Dec. 11.

The agency said the 6.4 million bpd is an increase of 800,000 bpd from 2011, with 7.1 million bpd forecast for 2013, a domestic production level which would be the highest annual average rate since 1992.

EIA said onshore Lower 48 crude production "is being driven by drilling activity in tight oil formations in Texas, North Dakota and Montana."

The Bakken, in the Williston Basin in North Dakota and Montana, and Eagle Ford in the Western Gulf Basin in Texas, "are frequently referenced as the key productive plays in the United States and contribute about two-thirds of U.S. tight oil production," the agency said.

The third key domestic growth area is the Permian Basin in East Texas, including plays such as Spraberry, Bonespring and Wolfcamp. The Permian "consists of layers of tight and conventional oil formations," EIA said, with the majority of drilling in the region consisting of vertical wells producing from a number of overlapping formations. There are more than 400 active drilling rigs in the Permian, "by far the most of any U.S. basin," and EIA said those rigs are "drilling a large number of wells very quickly."

EIA said Permian Basin production is estimated to have surpassed 1.25 million bpd in November, 33 percent more than the estimated 930,000 bpd in the Western Gulf Basin and 45 percent more than the 860,000 bpd in the Williston Basin.

Alaska North Slope crude oil production reached a seasonal low of 400,000 bpd during summer maintenance in August, the agency said, and has recovered to 560,000 bpd. EIA said it expects Alaska crude to average 530,000 bpd this year, about 6 percent lower than in 2011, and 520,000 bpd in 3013.

Net imports falling

In 2005, more than 60 percent of U.S. liquids fuel consumption was from imports, including crude oil, EIA said.

In 2011 that dropped to an average of 45 percent, down from 49 percent in 2010, and it expected to drop to 40 percent this year, EIA said, "as a result of continued substantial increases in oil production, an increase in net petroleum product exports, and an overall decline in liquid fuel consumption."

With projected increases in domestic crude oil production, that number is expected to drop to 37 percent in 2013, and that would "be the first time since 1991 that the share of total U.S. consumption met by liquid fuel net imports is less than 40 percent," the agency said.

EIA's Annual Energy Outlook 2013 reference case, released in early December, has the import share continuing to decline to 34 percent in 2019, "with slow increases thereafter."

EIA said it expects the Brent crude oil spot price to average $110 per barrel in the fourth quarter and the West Texas Intermediate crude oil spot price to average $89. Brent is forecast to average $104 per barrel next year, WTI $88.

The WTI discount to Brent averaged $23 per barrel in November and is expected to

"Even with the projected increases in the second half of 2012, production growth has slowed from its strong upward trajectory seen in 2009-11," the agency said, adding that it "expects that growth in associated gas from crude oil production, as well as continued drilling in liquids-rich areas, will continue to offset the decline in drilling activity."

fall to $11 per barrel by the fourth quarter next year, the agency said.

Brent is projected to average $112 per barrel this year and WTI $89 per barrel in the fourth quarter, with the WTI discount to Brent expected to average $21 in the fourth quarter before falling to $11 by the end of 2013.

Henry Hub at $3.54

The Henry Hub spot price for natural gas averaged $3.54 per million British thermal units in November, up 23 cents from the October average and 30 cents above the November 2011 average.

EIA said it expects the Henry Hub spot price to average $2.78 per million Btu this year and $3.68 in 2013.

U.S. natural gas inventories hit a record level of 3.929 trillion cubic feet Nov. 2, "surpassing the previous record set the week before," the agency said.

The record high at the end of the injection season "was due mainly to a high level of gas going into the injection season, rather than strong injection levels," the agency said. The increase of 1.446 tcf in working gas inventory during the 2012 injection season (April through October), was small by historic standards, EIA said, noting that the 2011 inventory build was 2.224 tcf.

EIA's forecast for U.S. marketed natural gas production in 2012 is 69.2 billion cubic feet per day, up 0.4 bcf from the November forecast, partly in recovery from hurricane Isaac in August, but also reversing several months of decline earlier in the year. The September volume, 69.4 bcf per day, "was slightly higher than January 2012 and the highest since February 1973 despite the decline in the natural gas rig count earlier this year," the agency said.

Baker Hughes reported the natural gas rig count at 417 as of Dec. 7, down from 811 at the beginning of the year, EIA said.

Total marketed production is forecast to average 69.6 bcf per day next year.

"Even with the projected increases in the second half of 2012, production growth has slowed from its strong upward trajectory seen in 2009-11," the agency said, adding that it "expects that growth in associated gas from crude oil production, as well as continued drilling in liquids-rich areas, will continue to offset the decline in drilling activity." ●

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● NATURAL GAS

Parnell: $355 million for Fairbanks gas

Major financial package would finance North Slope liquefaction plant and fund storage and distribution infrastructure across Interior

By ERIC LIDJI

For Petroleum News

In advance of the upcoming legislative session, Alaska Gov. Sean Parnell is proposing a $355 million financial package designed to bring natural gas to Fairbanks by late 2015.

The bulk of the package, to be introduced through legislation, would be $275 million in Alaska Industrial Development and Export Authority loans and bonding authorizations to spur private construction of a North Slope liquefaction plant. The package also includes $50 million from the general fund and $30 million in existing gas storage tax credits, which could go toward the plant, or toward local distribution lines or other infrastructure.

GOV. SEAN PARNELL

The primary goal of the project is to bring liquefied natural gas and propane to Fairbanks and to rural Interior communities along the road and river system, but it could also serve Southcentral markets, Parnell said. "The state has stepped up with a financial package that will lead to lower heating and electric costs," Parnell said in a statement on Dec. 7. "And, it can be a springboard for cheaper energy for Alaskans in other communities.

The project would deliver gas at $12 to $15 per 1,000 cubic feet to homeowners, Parnell told the Fairbanks Daily News-Miner, cutting heating bills in half compared to oil. The goal is to bring the project online by 2015, with expansions continuing for years to come.

The effort is meant to alleviate high fuel costs while the state and industry continues to pursue a natural gas pipeline that would eventually supply local markets directly.

Eying all major users

Alongside the announcement, AIDEA put of the call for "a single full-service entity, or an organized team of entities, that can participate in financing, planning, design, construction, commissioning, and operating the North Slope LNG Plant program."

The letter imagines a modular facility capable of producing between 7 billion and 9 billion cubic feet of LNG per year, but able to expand to 20 bcf per year, if needed.

Among the potential customers, AIDEA listed the local distribution company Fairbanks Natural Gas LLC, the local electric cooperative Golden Valley Electric Association, the oil refiner Flint Hill Resources, the new municipal entity Interior Alaska Natural Gas Utility and "other customers within Alaska that would benefit from LNG availability."

For weeks, Fairbanks Natural Gas has claimed to be ready to begin construction on a North Slope liquefaction facility, while GVEA is currently permitting a similar operation at a different location. Flint Hills was originally partnering with GVEA, but backed out because of its improved energy economics and because it hesitated to take the lead on a project increasing designed to address numerous energy issues for the entire region.

AIDEA is accepting responses through Jan. 8.

While Fairbanks Natural Gas President Dan Britton praised the proposal to the News-Miner as potentially lowering the risk of the project, Fairbanks North Star Borough Mayor Luke Hopkins, a force behind IANGU, questioned the amount of grant funding. "$50 million? I was hoping to see a lot more," he said. "I ask, is this the plan that gets us the lowest cost energy? We have to see how all this breaks out. When you have bonds that have to get paid back, that gets all put on the back of the ratepayers." ●

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● FINANCE & ECONOMY

Husky gets steamed up

Benefits from lower capital costs as it pushes ahead with SAGD in Saskatchewan, targeting 55,000 bpd by 2017 from smaller projects

By GARY PARK

For Petroleum News

Husky Energy, after quietly assembling the pieces, has emerged as the key player in extending thermal oil production eastward from Alberta into the province of Saskatchewan at capital costs that could benefit oil sands in-situ development.

In announcing a capital budget of C$4.8 billion for 2013, up about C$100 million from this year, it forecast production growth to 310,000-330,000 barrels of oil equivalent per day next year from 301,000 boe per day in 2012 and set annual growth of 5 percent to 8 percent in the 2012-17 period.

It's all part of the reshaping of the company under Chief Executive Officer Asim Ghosh, who has been at the helm for two years.

He told analysts "thermal production for us is already big and is getting bigger" as the company applies the technology to target 55,000 barrels per day by 2017.

He said the thermal operation gives Husky a "second plank to supplement our historical dependence" on cold heavy oil production with sand.

Many of the thermal projects are being developed in Husky's heavy oil areas of Lloydminster, which straddles the Alberta-Saskatchewan border.

Smaller SAGD projects

One of the smaller, yet potential key elements is a bundle of smaller projects using the same steam-assisted gravity drainage technology that is rivaling the discredited mining operations in Alberta's oil sands.

For Husky, SAGD is providing a breakthrough in capital costs in Saskatchewan where its Pikes Peak South project is expected to come online at a cost of C$24,000 per flowing barrel, while the Paradise Hill project is already producing for an outlay of C$28,000 per flowing barrel.

That compares with the expected capital investment of C$68,000 per flowing barrel for Husky's Sunrise SAGD project in Alberta.

Asked to explain the difference, Chief Operating Officer Rob Peabody said the company's many years of experience in thermal heavy oil allows it to use a cookie-cutter approach in building its small Saskatchewan SAGD projects.

"I think we will see further capital efficiencies in oil sands in-situ projects as well," he said, noting that the 60,000 bpd first phase of Sunrise, which is scheduled to produce first oil in 2014, includes some infrastructure that will be used in later phases.

But Peabody said it is not fair to make a direct comparison between Sunrise Phase 1 and the Saskatchewan SAGD projects because Sunrise does not have a significant amount of pre-investment for future phases.

However, Husky's Saskatchewan program is verging on steady growth, including sanctioning of its 10,000 bpd Rush Lake project, 2,000 bpd more than originally planned, with first oil expected in 2015.

In addition, its Pikes Peak South and Paradise Hill projects are expected to exit 2012 with production at 40 percent of their targeted combined output of 11,000 bpd, while commissioning of the Sandhill development is on target for 2014.

The original Pikes Peak operation has been producing since 1982, passing the 50 million barrel milestone about 2005.

Other planned thermal projects for Saskatchewan include Dee Valley (3,500 bpd by 2015-16), Edam East (8,000 bpd by 2016-17), Edam West (3,500 bpd by 2016-17) and four more prospects rates as candidates for 4,000-

see HUSKY ENERGY page 12

● EXPLORATION & PRODUCTION

Waiting game for North Slope explorers

BRPC and UltraStar continue to wait before finalizing plans, four other companies progressing through preliminary work

By ERIC LIDJI

For Petroleum News

As the year comes to a close, several small independents have yet to finalize their exploration plans for the winter while larger players advance on preliminary work.

Depending on how those plans shake out, this season could feature between four and six companies drilling between nine and 23 exploration wells across the North Slope.

Alphabetically, the six are Brooks Range Petroleum Corp., ConocoPhillips, Linc Energy Inc., Pioneer Natural Resources Alaska Inc., Repsol and UltraStar Exploration LLC.

While ConocoPhillips, Linc, Pioneer and Repsol have advanced to the permitting stage for their work, BRPC and UltraStar are waiting on final details before moving forward.

BRPC facing logistics

Brooks Range Petroleum Corp. is still pursuing as many as five wells and sidetracks at its Tofkat and Kachemach prospects this winter, but has yet to finalize work at either field.

BRPC hopes to drill an exploration well and as many as two sidetracks this winter at its Tofkat unit. Because the unit sits along a bend in the Colville River, the company needs to secure an appropriate rig and finalize the logistics of getting it across a channel of the river before it can move ahead. BRPC "continues to progress these and other issues that are critical to the execution of the Tofkat No. 2 drilling for this upcoming season," BRPC Chief Operating Officer Bart Armfield told Petroleum News by e-mail on Dec. 10.

In early 2008, BRPC drilled the Tofkat No. 1 well and two sidetracks. The well collected 10 oil samples from four sandstone reservoirs and found six feet of net pay in

While ConocoPhillips, Linc, Pioneer and Repsol have advanced to the permitting stage for their work, BRPC and UltraStar are waiting on final details before moving forward.

the Kuparuk formation, the deepest zone tested. The Tofkat No. 2 well would "test Brookian 3D anomalies, confirm the size of our Kuparuk discovery and test the deeper Jurassic offsetting two high flow rate Jurassic wells in ConocoPhillips' Nanuq field area."

BRPC is also still maintaining plans to drill as many as two wells at the Kachemach unit, just east of Tofkat, but the program "remains under consideration within the (Department of Natural Resources), and we are not at liberty to speculate as to the response that may come from the decision issued by the DNR," Armfield told Petroleum News.

As it pursue its two exploration ventures, BRPC is putting the final agreement together on its plans to develop the Mustang field in the Southern Miluveach unit. The Alaska Industrial Development and Export Authority recently agreed to finance a gravel road and pad at the unit, located at the southwestern corner of the Kuparuk River unit.

The mining, construction and conditioning will run from early 2013 through early 2014.

Cassin for Conoco

ConocoPhillips recently applied for a permit to drill in the federal Bear Tooth unit.

The company is asking for permission to drill the Cassin No. 1 well in the National Petroleum Reserve-Alaska unit, according to U.S. Bureau of Land Management filings.

Cassin No. 1 would be on lease AA081754, in the middle of the unit. The lease is included in Unit Area A, a subset of the unit designated for initial work commitments.

Earlier this year, ConocoPhillips staked nine potential well locations in the NPR-A, two in its Mooses Tooth unit and seven in the Bear Tooth unit (five wells and two sidetracks).

The company must drill by June 1, 2013, to meet its work commitments.

Petroleum News previously reported that ConocoPhillips had also applied to drill the Cassin No. 6 well in the unit, but the BLM has yet to publish an application notice.

Snow road for Linc

Linc Energy is nearly done building a 100-mile snow road to its Umiat field.

With the road complete, the Australian independent will begin mobilizing crews and equipment for its five-well program at the oil field in the Brooks Range Foothills.

Using the Kuukpik No. 5 rig, Linc plans to drill the side-by-side Umiat No. 16 and Umiat No. 16H wells, the Umiat 23 well and "one or both" of the Umiat No. 18 and Umiat No. 19 wells. The program will begin with the Umiat DS No. 1, Class II disposal well.

Nuna permit for Pioneer

The Alaska Oil and Gas Conservation Commission issued a permit on Dec. 4 for Pioneer Natural Resources Alaska to drill Oooguruk NDST-02, also known as Nuna No. 2.

Like the NDST-1 or Nuna No. 1 exploration well that Pioneer drilled this past winter, NDST-2 will be a directional well starting from an onshore ice pad at the Kuparuk River unit and continue to an offshore bottom-hole location on Pioneer lease ADL 355038.

Pioneer is using the well to collect additional information about the Torok reservoir at its near shore unit. The

see **EXPLORATION** *page 13*

● LAND & LEASING

Buccaneer applies for unit at Kenai Loop

By KRISTEN NELSON

Petroleum News

Buccaneer Alaska Operations LLC, which has been producing natural gas from its 2011 Kenai Loop No. 1 discovery well since January, has applied for a 7,500-acre Kenai Loop unit.

The proposed unit is on the northern Kenai Peninsula on a ridge between the Cannery Loop and Beaver Creek fields.

The Alaska Department of Natural Resources Division of Oil and Gas said in a public notice that the proposed unit covers some 1,397 acres within four State of Alaska oil and gas leases, some 4,828 acres within two Alaska Mental Health Trust leases and some 1,275 acres within one State of Alaska Cook Inlet Region Inc. lease.

Buccaneer holds 100 percent working interest in the leases.

The application, noticed by the division Dec. 10, was submitted in July. Typically the division has questions about a proposal and only issues a public notice asking for comments when an application is deemed complete.

Without unitization the state leases would have expired in September; the Mental Health Trust and CIRI leases expire in 2016. The Kenai Loop No. 1 well is on one of the Mental Health Trust leases and that lease is held by production.

The proposed unit is on the northern Kenai Peninsula on a ridge between the Cannery Loop and Beaver Creek fields.

Buccaneer said in its application that it had spent more than $48 million exploring and developing the proposed unit area.

Production facilities for the Kenai Loop No. 1 well were completed in January.

Buccaneer said in its initial plan of development that it would drill one to three additional wells in the first year of the unit, beginning with Kenai Loop No. 4. That well was spud in September.

Buccaneer also said it would propose an initial participating area for the Tyonek formation, encompassing the known producing interval in the Kenai Loop No. 1.

For the second through fifth years of the five-year unit plan, Buccaneer said it would drill one to three additional wells per year in the Kenai Loop unit.

Buccaneer told the division that the Kenai Loop No. 1 discovery well, drilled in April 2011, was placed according to available but limited 2-D seismic data.

Logs from that well "indicate that multiple gas zones in the Beluga and Upper Tyonek formations were intersected while drilling," Buccaneer said, and estimated total gross pay of 645 feet. Initial testing of the Kenai Loop No. 1 flowed gas to the surface at more than 10 million cubic feet per day from two zones in the Upper Tyonek, some 60 feet of net pay out of 87 feet of gross pay in the two zones. The company said that additional zones remained untested, as the rig needed to be released back to Marathon June 1, 2011.

Buccaneer began sustained production Jan. 14 and in July was producing at 5 million cubic feet per day. In October the company reported that production had been increased to 6 million cubic feet per day.

A second well, Kenai Loop No. 3, was drilled in August 2011 but was a dry hole.

Last April Buccaneer completed a 3-D seismic program covering 23.4 square miles, allowing the company "to fully image" all acreage in the proposed unit.

Comments on the application are due to the division Jan. 14. Non-confidential portions of the application are available on the division's website at www.dog.dnr.state.ak.us/Units/Units.htm#recentpubnot. ●

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continued from page 10

HUSKY ENERGY

5,000 bpd each after 2017.

In the Alberta oil sands, the first phase of the 50 percent owned Sunrise project is on schedule for first oil in 2014.

Construction of the initial phase is half finished, with 85 percent of the C$2.7 billion price tag now fixed. Regulatory approvals are in hand for up to 200,000 bpd of production from Sunrise. ●

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● NATURAL GAS

Report: LNG exports would be good for US

Responding to 15 requests for export authorization, DOE commissions NERA analysis of impact of natural gas exports on US economy

By KRISTEN NELSON
Petroleum News

Exports of liquefied natural gas would benefit the U.S. economy, but depending on worldwide market conditions and the U.S. price of natural gas, the United States probably wouldn't see maximum exports. That was the conclusion of a study done for the U.S. Department of Energy by NERA Economic Consulting, released in early December.

Under the Natural Gas Act, DOE's Office of Fossil Energy authorizes exports of natural gas, including LNG. For countries without free trade agreements with the United States, exports of natural gas are presumed to be in the public interest unless DOE determines, after opportunity for a hearing, that such exports would not be in the public interest.

When it conditionally authorized exports by Sabine Pass Liquefaction to non-free trade nations in 2011, DOE noted its continuing duty to monitor domestic supply and demand conditions to ensure LNG exports don't result in a reduction of natural gas needed to meet domestic needs.

DOE said it has 15 applications to export LNG from the Lower 48 to non-free trade nations.

The NERA study, like a study completed in early 2012 by the Energy Information Administration, is part of the proceedings for the 15 applications.

Alaska not included

DOE noted that Alaska was not included in the study of domestic impacts of natural gas exports. Because there is no natural gas pipeline interconnection between Alaska and the Lower 48, economic consequences of exporting LNG from Alaska "are likely to be discrete and separate" from consequences of exports from the Lower 48, DOE said.

"This report will reassure Alaska producers and ratepayers that our export opportunities are absolutely still on the table," U.S. Sen. Mark Begich, D-Alaska, said in a Dec. 5 statement. "A large-scale LNG export project in Alaska dramatically improves the economics of a gasline from the North Slope, helping bring down energy prices for Alaskans and creating jobs," Begich said.

NERA used scenarios developed by EIA and said it "concluded that in many cases the world natural gas market would not accept the full amount of exports specified ... in the EIA scenarios at prices high enough to cover the U.S. wellhead price projected by EIA."

U.S. Sen. Lisa Murkowski, R-Alaska, ranking Republican on the Senate Energy and Natural Resources Committee, said that based on the findings of the study, it may be time to revisit the approval process for exporting LNG to non-FTA countries.

"The conclusions in this report on the benefits to the economy should inform the DOE approval process regarding exports. This is a really good report and it really does provide guidance as we move forward," Murkowski said in a Dec. 5 statement.

Building on EIA report

NERA built on the EIA study of the relationship between export levels and domestic prices.

"The EIA study was limited to the relationship between export levels and domestic prices without considering whether or not those quantities of exports could be sold at high enough world prices to support the calculated domestic prices. The EIA study did not evaluate macroeconomic impacts," NERA said.

NERA used its global natural gas model to estimate expected levels of U.S. exports under different scenarios for global natural gas supply and demand, while the firm's energy-economy model was used to determine domestic macroeconomic impacts from different levels of LNG exports.

Across all the scenarios, "the U.S. was projected to gain net economic benefits from allowing LNG exports," NERA said, with benefits from export expansion more than outweighing "losses from reduced capital and wage income to U.S. consumers."

Impact of shale

NERA said the U.S. benefits most if it "becomes able to produce large quantities of gas from shale at low cost, if world demand for natural gas increases rapidly, and if LNG supplies from other regions are limited. If the promise of shale gas is not fulfilled and costs of producing gas in the U.S. rise substantially, or if there are ample supplies of LNG from other regions to satisfy world demand, the U.S. would not export LNG."

The study said natural gas prices do rise in the U.S. when LNG is exported.

"But the global market limits how high U.S. natural gas prices can rise under pressure of LNG exports because importers will not purchase U.S. exports if U.S. wellhead price rises above the cost of competing supplies."

NERA also said the U.S. natural gas price "does not become linked to oil prices in any of the cases examined."

The rise in domestic gas prices remains "in a relatively narrow range across the entire range of scenarios," with a range of increases from zero to 33 cents per thousand cubic feet in 2010 dollars, and the largest observed increase a rise of 20 cents to $1.11 per thousand cubic feet.

"The higher end of the range is reached only under conditions of ample U.S. supplies and low domestic natural gas prices, with smaller price increases when U.S. supplies are more costly and domestic prices higher," NERA said.

US wellhead price critical

NERA used scenarios developed by EIA and said it "concluded that in many cases the world natural gas market would not accept the full amount of exports specified ... in the EIA scenarios at prices high enough to cover the U.S. wellhead price projected by EIA."

At maximum volumes of domestic natural gas available,

see **NERA REPORT** page 14

continued from page 11

EXPLORATION

company plans to hydraulically fracture and flow test NDST-2.

Four locations for Repsol

Repsol E&P USA Inc. is permitting four locations in the fairway between the Oooguruk and Colville River units: Qugruk No. 1, No. 3 and No. 6, and the alternate Qugruk No. 5.

The program calls for using three rigs to drill a vertical well and as many as two sidetracks at three locations. The Spanish major permitted Qugruk No. 1 and Qugruk No. 3 in 2011. Qugruk No. 6 is a new well at the location where Repsol began drilling the Qugruk No. 2 well last winter, before a shallow gas kick compromised operations.

Repsol plans to use Nabors rig 105AC at Qugruk No. 1, Nabors rig 99 at Qugruk No. 3 and Nabors rig 9ES at either Qugruk No. 6 or at the alternate Qugruk No. 5 location.

UltraStar still waiting

UltraStar continues to wait on the financial backing for its wells this winter.

Earlier this summer, UltraStar executive Jim Weeks was optimistic the Alaska-based independent would be able to drill the North Dewline No. 1 well in the first quarter of 2013, but as of early October Weeks said the company still needed half the money.

On Dec. 12, Weeks told Petroleum News, "We're about in the same place." ●

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● ENVIRONMENT & SAFETY

Study looks at Port Valdez wave problem

University of Alaska Anchorage researchers recommend tactics to avoid weather-related disruptions in the loading of oil tankers

By WESLEY LOY
For Petroleum News

A new study suggests ways to avoid weather-related disruptions in oil loading at the tanker dock in Valdez.

The study, still in draft form, is the work of Maria Kartezhnikova, a graduate student in the University of Alaska Anchorage School of Engineering; her professor, Orson Smith; and Peter Olsson, Alaska state climatologist with UAA's Environment and Natural Resources Institute.

Strong winds out of the east can be a serious problem at the Valdez Marine Terminal, where tankers arrive regularly to load Alaska North Slope crude oil.

The terminal operator, Alyeska Pipeline Service Co., deploys boom around tankers during loading as a precaution against spills.

> *"If the port is open and tankers are at anchor, we put crews and equipment in the water to set boom. We won't send crews out for that activity unless it is safe to do so."*
> **—Alyeska spokeswoman Michelle Egan**

Wind-driven waves can prevent safe deployment of boom, or overtop the boom. This can prevent or interrupt tanker loading, and ultimately can force the curtailment of oil production from the North Slope.

In November 2006, for example, high wind and waves forced a shutdown of the 800-mile trans-Alaska pipeline, which brings the oil to the Valdez terminal. The pipeline shutdown was necessary because tankers couldn't load and the terminal's storage tanks were full.

'Wind and wave shelter'

The researchers looked at wind patterns at Port Valdez, and considered ways to reduce oil loading disruptions during sustained winds of 30 knots and waves of 2½ feet.

They focused on Berth 4, one of the two active tanker loading berths at the Valdez Marine Terminal.

They recommend "operational experiments" such as deploying another length of oil boom upwind of the primary boom, or positioning a tug and barge with their hulls aligned across the wind to create a "wind and wave shelter" for Berth 4.

see **PORT STUDY** *page 15*

● NATURAL GAS

Another Fairbanks natural gas option?

When Southcentral utilities start importing gas to bolster local supplies, could some of the imported gas go to Fairbanks?

By ALAN BAILEY
Petroleum News

There are currently several proposals on the table for bringing new natural gas supplies into Fairbanks in Alaska's interior by building a gas liquefaction facility on the North Slope and then trucking liquefied natural gas, or LNG, south on the Haul Road.

But, with Southcentral gas and power utilities in the initial stages of planning for the import of LNG or compressed natural gas into Southcentral to bolster dwindling gas supplies from the Cook Inlet basin, could some of this imported gas provide a more cost-effective solution to the Fairbanks fuel supply conundrum?

Fairbanks Natural Gas LLC has for a number of years been trucking LNG to Fairbanks from Southcentral, using LNG manufactured from Cook Inlet gas at a small plant near Anchorage. Tightening gas supplies from the Cook Inlet have caused the Fairbanks utility to pursue the possibility of obtaining its LNG from the North Slope.

> *Fairbanks requires a similar volume of gas to the initial needs for Southcentral and could perhaps help underpin that longer-term import arrangement, Posey said.*

Fairbanks LNG

On Dec. 12 during Law Seminars International's Energy in Alaska conference in Anchorage, Jim Posey, general manager of Anchorage utility Municipal Light & Power, commented that, assuming that the import of gas into Southcentral goes ahead, it would make sense to ship some of that gas as LNG to Fairbanks, as an alternative to the Fairbanks supply coming from the North Slope. Essentially the road trip from Southcentral to Fairbanks would be more cost effective than the trip from the North Slope — the road system from the Slope is unpaved for much of its length and crosses the Brooks Range over the 4.700-foot-high Atigun Pass.

Arithmetic

"There's a 500-mile gravel road to Fairbanks from the North Slope. There's a 300-mile paved road from here," Posey said.

see **FAIRBANKS GAS** *page 15*

continued from page 13

NERA REPORT

"it is cost-effective to export U.S. LNG with or without any international supply or demand shocks," NERA said, but with lower volumes of U.S. natural gas, and a higher price, the study model showed no U.S. LNG exports.

The study also concluded that net domestic benefits of LNG exports "could be larger if U.S. businesses were to take more of a merchant role. Based on business models now being proposed, this study assumes that foreign purchasers take title to LNG when it is loaded at a United States port, so that any profits that could be made by transporting and selling in importing countries accrue to foreign entities."

NERA said that in cases it studied where exports are constrained, the model with foreign purchasers taking title in the U.S. "sacrifices additional value from LNG exports that could accrue to the United States." ●

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continued from page 14

PORT STUDY

The researchers rule out installing a floating harbor breakwater, due in part to the navigational hazard it could pose.

The Prince William Sound Regional Citizens' Advisory Council had a hand in the study, agreeing to provide up to $2,500 to cover travel expenses for the researchers to visit Valdez and the marine terminal.

Alyeska is supportive

Alyeska spokeswoman Michelle Egan told Petroleum News on Dec. 12 that Alyeska hadn't yet had an opportunity to review the wave research in depth.

"We support the UAA School of Engineering and value the opportunity to review its scholarly work and consider its application for our operation," Egan said.

Weather is a factor for tanker loading and does cause delays, she said.

"Sometimes Port Valdez is closed due to weather and tankers wait outside the entrance," Egan said. "If the port is open and tankers are at anchor, we put crews and equipment in the water to set boom. We won't send crews out for that activity unless it is safe to do so."

If boom is set and water is splashing over it, oil can't be loaded onto tankers, she said.

Loading delays are common through the winter months, Egan said.

The "perfect storm" is when crude inventory is high at Valdez, weather is poor and tankers can't load, she said.

At that point, "pressure mounts all the way up to the North Slope," Egan said.

Oil producers must "prorate" or dial down their output until some inventory can be moved onto tankers.

"The further we prorate, the closer we get to a shutdown," Egan said, which is highly undesirable in winter due to the potential for pipeline freeze-ups and other problems. ●

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GOVERNMENT

NOAA chief Lubchenco to step down

Jane Lubchenco, administrator of the National Oceanic and Atmospheric Administration, will soon leave the post.

Lubchenco is a marine ecologist and environmental scientist who was teaching at Oregon State University when the Obama administration chose her as NOAA administrator.

Multiple media outlets reported Lubchenco on Dec. 12 wrote to NOAA employees that she would step down at the end of February "to return to my family and academia."

"I can confirm that she announced her intent to leave NOAA," Ciaran Clayton, director of communications for the agency, told Petroleum News.

Lubchenco is a marine ecologist and environmental scientist who was teaching at Oregon State University when the Obama administration chose her as NOAA administrator.

She became a prominent public figure as the government responded to the Deepwater Horizon blowout and oil spill in the Gulf of Mexico in 2010.

Formed in 1970, NOAA is a Commerce Department agency of considerable importance to the oil and gas industry. NOAA conducts extensive scientific research, and is home to subagencies such as the National Marine Fisheries Service, the National Weather Service and the National Ocean Service.

—WESLEY LOY

continued from page 14

FAIRBANKS GAS

Dan Britton, president and CEO of Fairbanks Natural Gas, has told Petroleum News that he sees the high cost of LNG on world markets as an impediment to the idea of using imported gas as a supply for Fairbanks.

"Arithmetic says you ought to give that a consideration," Posey commented to Petroleum News.

And, given that price terms for a longer-term gas import contract would likely be better than for a short-term contract, the purchase of imported gas for Fairbanks could improve the overall economics of the gas import arrangements. A 15 to 20 year purchase contract, for example, would bring the cost of gas down — Fairbanks requires a similar volume of gas to the initial needs for Southcentral and could perhaps help underpin that longer-term import arrangement, Posey said.

In the absence of a large, new gas field coming on line in the near term, the Southcentral utilities see a need to import gas in the winter of 2014-15 to fill a projected shortfall in Cook Inlet gas supplies. The utilities hope that imports will be a temporary phenomenon, filling the supply shortfall until Alaska internal gas supplies can be restored to adequate levels, either from Cook Inlet gas fields or through a pipeline from the North Slope. The utilities expect to decide on their import plan by the end of March, Posey said.

Cost of gas

Dan Britton, president and CEO of Fairbanks Natural Gas, has told Petroleum News that he sees the high cost of LNG on world markets as an impediment to the idea of using imported gas as a supply for Fairbanks. The imported gas would be expensive relative to the cost of gas from the North Slope, Britton thinks.

"For Fairbanks and the Interior we feel that LNG from the North Slope has a higher likelihood, primarily because of cost," Britton said. ●

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LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Cook Inlet	spring 2013
DNR	Alaska Peninsula	spring 2013
DNR	Beaufort Sea Areawide	fall 2013
DNR	North Slope Areawide	fall 2013
DNR	North Slope Foothills Areawide	fall 2013
BLM	NPR-A	fall 2013
BOEM	Cook Inlet (special interest)	2016
BOEM	Chukchi Sea	2016
BOEM	Beaufort Sea	2017

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

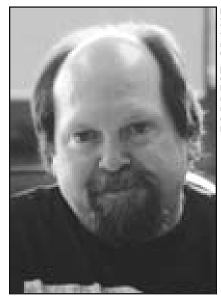
This week's lease sale chart sponsored by:

Geokinetics

Petroleum news

Oil Patch Bits

GBR Equipment's Robert Reynolds passes away


FORREST CRANE

ROBERT E. REYNOLDS

GBR Equipment said Dec. 7 that its vice president and long-time Alaska resident Robert E. Reynolds, known to his friends and family as "Bobby" or "Catfish," died Dec. 4 at Providence Hospital Alaska, surrounded by friends and family.

He was the youngest of four brothers and was born to John and Rita Reynolds in Midland, Texas, on Feb. 27, 1954. Bobby's family moved to Alaska in 1967. Bobby graduated from East Anchorage High School in 1972 and went to work in the oilfield business in Prudhoe Bay in 1973. He worked for Brinkerhoff Drilling as a roustabout for a few years and then went to work for Parker Drilling as a floor hand and eventually worked his way up to driller. In 1984 Bobby went to work for his father John Reynolds at GBR Equipment. Bobby worked for the family business for many years and eventually became a partner in the company business with his brother Billy.

Bobby was an avid hot rod and motorcycle enthusiast and was well known in the motorcycle community in Anchorage. He loved to golf and hang out on his boat at the lake. His favorite sports were baseball and football.

Bobby's friends and family say you would have to search the world over to find someone with a heart as big as Bob's. He was always willing to help anyone in need and everybody loved him for it.

Vigor Marine completes 300-ton bow replacement


COURTESY VIGOR MARINE

Vigor Marine said Dec. 6 that in just less than three months it replaced the bow of Olympic Spirit, an 80,000-barrel double-hull petroleum barge owned by Harley Marine subsidiary, Olympic Tug & Barge Inc. Meeting the aggressive schedule has helped keep Harley's fleet in the water where it needs to be to continue to provide quality marine services.

The bow replacement of Olympic Spirit was necessitated by some mistakes that were made during the original construction of the barge. Harley worked closely with naval architect, Elliott Bay Design Group, on the most effective strategy to bring Olympic Spirit up to Harley's standards of excellence. It was decided a total bow replacement was the best solution. The 300-ton bow module was pre-built in a section of

see **OIL PATCH BITS** *page 17*

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

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

continued from page 1

CANADIAN BEAUFORT

Ramsay is also certain that oil will be the primary target if exploration goes into full swing, based on estimates that the Canadian section of the Beaufort holds 90 billion barrels of recoverable oil, but Imperial is sticking to its traditional line, refusing to choose between oil and natural gas.

He said the key players in the Canadian Arctic are "anxious to move forward and are looking at the Beaufort as an opportunity" to ship oil to southern Canadian and United States markets.

Ramsey touts potential

That prospect would be bolstered if there was a major find in the Canol shale play of the Central Mackenzie Valley, he said.

Ramsay is so bullish on the Beaufort that he told delegates at the Arctic Technology Conference in Houston in early December that "based on geological analyses from the U.S. Geological Survey as well as our own advisers, the potential discoveries (of oil and gas) in the waters off the coast of the NWT may rival the Gulf of Mexico."

But he conceded that the first commercial development is more likely to come from the Central Mackenzie Valley, not the Arctic coast.

"Experts have told us there are billions of barrels in the Central Mackenzie Valley," where tests have pointed to oil containing 20 percent to 60 percent liquids-rich gas, Ramsay said.

The hiatus in drilling Canada's Arctic offshore stems from a review of rules for Arctic offshore drilling, a process that was blindsided by BP's Macondo well blowout in the Gulf of Mexico.

Confidence in the industry's ability to safely explore and develop Arctic resources was further jolted when Royal Dutch Shell was forced stop work on one offshore Alaska well due to encroaching ice and held off completing its other wells.

That adds to the pressure on Imperial and its partners to convince Canada's National Energy Board that they have the technology to arrest any undersea blowout.

3-D seismic gathered

Rolheiser said the joint-venture trio gathered 3-D seismic data from their two large exploration blocks in 2007 and 2008, formed their partnership in mid-2010 and this year participated in geotechnical and environmental baseline work along with ArcticNet, an international network of scientists from universities and governments.

He said that Aboriginal Affairs and Northern Development Canada issued new exploration licenses to the partnership this year because of delays caused by the Arctic offshore review, effectively restarting the clock that gives the companies until 2019 or 2020 to start drilling and secure extended rights to the Beaufort permits if a significant discovery is reported.

Imperial has also been coy about whether it will conduct drilling from an ice-strengthened ship.

Of the two licenses, BP acquired one in 2008 for a work commitment of C$1.18 billion, while sister companies Imperial and ExxonMobil obtained their lease in 2010 for a spending pledge of C$585 million.

Central Mackenzie Valley focus

While the Mackenzie Gas Project, designed to ship up to 1.8 billion cubic feet per day of Arctic gas to North American markets, is held up indefinitely pending an improvement in the outlook for gas prices as well as reaching a fiscal agreement with the Canadian government, the focus in Canada's Arctic has shifted to the Central Mackenzie Valley where spending on roads and well-site preparations is expected to reach C$100 million this winter, Ramsay said.

Key operators in the area include MGM, whose two exploration licenses are under a farm-in agreement with Shell Canada, which has also made a combined work commitment of C$137 million for two licenses of its own. Other leading players are Husky Energy and ConocoPhillips Canada.

Ramsay said any oil discovered in the area would have immediate access to market through Enbridge's 40,000 barrels per day pipeline, which is currently operating at only 25 percent of capacity. The line from the aging Norman Wells oil field connects with the North American pipeline network at Zama in northwest Alberta.

He said there is also the possibility of a second oil pipeline and a natural gas pipeline, which could potentially carry gas for LNG export projects, being built out of the Central Mackenzie Valley.

MGM 'very excited'

MGM President Henry Sykes told a recent Peters & Co. conference his company is "very excited" about the extent of activity planned for the Canol this winter, which he described as "significant, given that this play wasn't on the radar screen two years ago."

Husky drilled two wells last winter at its lease and completed 220 square miles of 3-D seismic over two exploration blocks adjacent to MGM's project.

Husky said it plans to further evaluate its two wells this winter and build an all-weather road, which Sykes noted is a "very expensive" undertaking, pointing to a level of commitment to the play.

On the long-quiet Mackenzie Gas Project, Rolheiser said his company still has a scaled-down employee group assigned to the venture.

He said the prospect of "dialogue on a fiscal agreement remains open" if either side wants to restart discussions. "We continue to see it as a viable opportunity under the right economic conditions. We continue to be hopeful."

—GARY PARK

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continued from page 16

OIL PATCH BITS

Vigor's 150,000 square feet of fabrication bays in its Swan Island shipyard in Portland, Ore., allowing the vessel to continue operations. As the module neared completion, the Olympic Spirit was transported to the Portland yard and lifted by one of Vigor's versatile drydocks and positioned at the end of an 800-foot long buildway. There the existing bow was removed and the new module was attached. The excellent design work provided by Harley and Elliott Bay allowed Vigor Marine teams to retain the forward collision bulkhead both speeding and simplifying installation. Solid teamwork was a key component to the success of this significant and complex project.

Crowley honored with multiple environmental awards

COURTESY CROWLEY

Crowley Maritime Corp. said Dec. 4 that it was recently honored by the Chamber of Shipping of America with 96 environmental achievement awards for safe vessel operations during 2012 — more than any of the other 76 maritime companies recognized by CSA. The vessels owned and/or operated by Crowley businesses qualified for the awards by operating for at least two consecutive years without any recordable environmental incidents — a testament to Crowley's continued commitment to operational excellence with a focus on environmental protection.

The CSA awards were presented in November at the Ronald Reagan International Trade Center in Washington, D.C., to several Crowley companies, including Crowley Liner Services, Crowley Marine Services, Crowley Petroleum Services, Crowley Puerto Rico Services, Crowley Technical Management Services, Marine Transport Lines and Marine Transport Management. The 96 vessels achieved a combined total of 970 years, based on each vessel operating two or more continuous years of service without an environmental incident.

"Safeguarding people and the environment is at the core of Crowley's culture," said John Tronti, managing director for MTL/Crowley, who accepted the awards on behalf of the company, along with Julio Custode from the Crowley-managed M/V Cape Washington. "The awards are a great reflection of our crewmembers and employees, who make this possible, and are a further indication to our customers and industry associates that we take pride in operating responsibly."

continued from page 1

DOYON WELL

appealing — gas from Nenana could provide a source of energy for power generation or could perhaps be piped to Fairbanks, to alleviate that city's cripplingly high energy costs.

Doyon had been exploring the basin under the terms of a state exploration license but has recently converted the bulk of the license area into state oil and gas leases. In partnership with Rampart Energy Co., Arctic Slope Regional Corp., Usibelli Energy LLC and Cedar Creek Oil & Gas Co., Doyon conducted seismic surveys in the more southern part of the basin in 2004 and 2005, supplementing some Shell seismic data from the 1980s that Doyon had licensed and reprocessed.

Nunivak No. 1 well

In 2009 the partnership drilled the Nunivak No. 1 well, about three miles west of the town of Nenana.

The well did not encounter an economic gas accumulation but provided intriguing evidence for the hydrocarbon potential of the basin. Samples from some of the coal seams that are thought to pervasive in the basin and that would form the primary hydrocarbon source, were found to contain hydrocarbons that appeared to have formed from the heating of the coal, rather than from the bacterial decomposition of organic debris. Soil samples from land over the basin contain trace quantities of a similar hydrocarbon mix. And a merging of data from the Nunivak No. 1 well with the seismic data and with proprietary gravity and magnetic data led to a complete re-assessment of the basin, a re-assessment that has pointed to much greater maximum basin depths than were previously thought to exist.

Although the basin has long been thought to be gas prone, Doyon has said that, with some parts of the basin perhaps as deep as 25,000 feet, there is the possibility of oil as well as gas in the basin.

Seven miles west

Encouraged by its findings from the Nunivak No. 1 well, Doyon is going to drill the No. 2 well about seven miles west of that first well. The new well will test a large structural closure in direct contact with the deeper part of the basin, James Mery, Doyon's senior vice president, land and natural resources, has told Petroleum News.

But Doyon's erstwhile partners have dropped out of this new exploration venture — the Nunivak No. 2 well will be a 100 percent Doyon project, Mery told Petroleum News in a Dec. 12 email.

In the winter of 2011-12 Doyon, also operating by itself, conducted a seismic survey in the more northerly part of the basin.

Road extension

According to the plan of operations for the new well the construction of a gravel access road to the well site will involve a six-mile westward extension to the access road constructed for the No. 1 well. The road runs within a city of Nenana right of way for access to agricultural land on the west side of the Nenana River. Equipment using the road has to cross the river by barge.

A 1.6 mile spur road will extend to the well pad from the road that is in the right of way, the plan says. The well location is section 7 of township 4 south, range 9 east, Fairbanks Meridian.

The 600-foot by 300-foot gravel drilling pad will support the drilling rig, processing facilities, a personnel camp, fire-fighting water, fuel, hazardous material storage, waste storage and vehicle parking.

Mery told Petroleum News that Doyon expects to use Nabors Rig 99, but that an agreement with Nabors has yet to be finalized.

—ALAN BAILEY

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Doyon to conduct survey in Yukon Flats

Doyon Ltd. the Native regional corporation for the Alaska interior, will shoot a 3-D seismic survey in the Stevens Village area of the Yukon Flats this winter, James Mery, Doyon's senior vice president, land and natural resources, told Petroleum News in a Dec. 12 email. SAExploration will conduct the survey, which will cover an area of about 50 square miles, Mery said.

For a number of years Doyon has been investigating the resource potential of the Yukon Flats basin, a sediment-filled depression in the Earth's crust between the trans-Alaska pipeline and the Canadian border. The corporation thinks that the basin has significant potential for holding both oil and gas resources. And new assessments of geophysical data for the basin have revealed the existence of several sub-basins within the main basin.

Doyon had decided to conduct a new seismic survey in the basin this winter but had not determined which of the sub-basins to tackle: The corporation was considering a reconnaissance 2-D survey over a sub-basin near the village of Birch Creek, or a more focused 3-D survey at Stevens Village, where the corporation has already shot a 2-D reconnaissance survey. The corporation has now opted for the Stevens Village survey, which, the corporation has said, would be used to identify specific drilling targets.

—ALAN BAILEY

continued from page 1

MUSTANG ROAD

Through Mustang Road, AIDEA and Brooks Range Petroleum plan to build five pieces of infrastructure in the coming year: a winter ice road, a gravel mine, a 19.3-acre gravel production pad, a 0.7-mile access road from the mine to the pad and a 4.4-mile open access road from the pad to the existing road system at the nearby Kuparuk River unit.

Under the deal, Brooks Range Petroleum is currently on the hook for the remaining $5 million needed to fund the project, expected to cost some $25 million, as well as "any additional cash calls required to complete the road and pad," should the project exceed its budget. The Brooks Range Petroleum portion of the funding is guaranteed by its parent company Alaska Venture Capital Group and its partner Ramshorn Investments Inc.

AIDEA is also interested in financing the $178.6 million production facility Brooks Range Petroleum would eventually need to build to bring the prospect online.

Brooks Range Petroleum would operate and maintain the open access road.

The deal involves an 8 percent rate of return over 15 years, which would bring AIDEA around $5.44 million. AIDEA believes existing tax credits will constitute 46 percent of the total capital cost, totaling some $11.5 million and reducing AIDEA's initial payments considerably. Mustang Road LLC will also become a 1 percent working interest owner in the Southern Miluveach unit, allowing AIDEA to collect royalties on future productions.

A mid-sized field

In addition to the potential to create jobs and increase North Slope oil production, AIDEA is interested in the Mustang project, in particular, because of its size and location.

While a Brooks Range Petroleum-commissioned study by DeGolyer & MacNaughton estimated the proved reserves of Mustang at 24.7 million barrels, an AIDEA-commissioned study by David Hite estimated 30.7 million barrels in proved reserves. (The Hite study, however, came in under the DeGolyer & MacNaughton study when it came to estimating the less likely "proved, probable and possible" reserves at Mustang.)

Additionally, the Mustang discovery wells are less than a mile from the Alpine Pipeline, making the project cheap by North Slope standards, from a transportation standpoint.

AIDEA rates 'very competitive'

Asked by the AIDEA board why his company sought public financing, Brooks Range Petroleum Chief Operating Officer Bart Armfield said they tested the waters in the Lower 48 and found the interest rates offered by AIDEA to be "very competitive." Additionally, Brooks Range Petroleum believes the Mustang project, if successful, could become a model, making it easier for smaller independents to get a toehold on the North Slope.

While AIDEA hopes to create a model it can replicate in the future, it also believes the Mustang road will improve the economics for other development projects in its vicinity.

In particular, AIDEA has already approached two nearby lessees, the Arctic Slope Regional Corp. subsidiary ASRC Exploration LLC and the Spanish major Repsol, about using the road as a staging area and said both companies seemed amenable to the idea.

AIDEA is also interested in financing the $178.6 million production facility Brooks Range Petroleum would eventually need to build to bring the prospect online.

In addition to the approval of its board, though, AIDEA would need authorization from the Alaska Legislature before it could participate in the larger financing project.

An emerging trend

In 2011, AIDEA took its first big leap into the oil and gas industry by helping Buccaneer Energy Ltd. purchase a jack-up drilling rig for exploring in shallow offshore regions.

Recently, Gov. Sean Parnell announced AIDEA would be the lead agency for issuing up to $275 million in loans to spur private construction of a North Slope liquefaction facility, a project designed to bring natural gas to the Interior and potential Southcentral. ●

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continued from page 1

HILCORP PROGRAM

reservoir engineering, coupled with the hard work of drilling and well remediation, recognizing that the Cook Inlet fields that it is operating are well past their initial bloom of youth.

"Initial production can actually be pretty forgiving, but when you're late in the life of the field you really have to work hard to get that extra bit of oil and gas out of the ground," Barnes said.

Hilcorp relies on the people working in the fields to use their local knowledge and expertise to reduce operating expenses while working with engineering staff to increase production rates, thus reducing the cost per barrel of products from the fields.

Swanson River

In the Swanson River oil field on the Kenai Peninsula, the first major oil field in the basin, with initial startup dating back to 1961, Hilcorp has been operating a drilling rig and using a pulling unit for well remediation, as well as bringing in a workover rig for well work.

"There are a lot of wells out there that need to be fixed," Barnes said. "We've scratched the surface and have a long way to go. … When we took it over it was making about 300 barrels a day and on this morning's report it was 2,200 barrels a day."

Hilcorp has recently completed a well that is now producing at more than 1,000 barrels per day, Barnes said.

Offshore oil

Most of Hilcorp's oil production is offshore, where the company has stripped out the old drilling rigs from the offshore platforms, in preparation for the use of modern equipment for much-needed well work. The company has been using a small pulling unit for well remediation as an interim arrangement, prior to obtaining workover rigs.

"We're having two proper workover rigs built that we'll use out there to pull wells in a more efficient way," Barnes said. "Those should be up and running spring of next year."

When the time is right, Hilcorp will move a modern drilling rig to the platforms to re-drill wells, as necessary, he said.

Hilcorp sees the large McArthur River field, where the company has already increased production by about 8 percent, as having the greatest potential of its Cook Inlet oil fields. Boosting production at McArthur River is a question of re-invigorating the field's old waterflood process and achieving efficient well completions, Barnes said.

Granite Point

The company also feels very positive about the prospects for its offshore Granite Point field, where production is up about 27 percent.

"Granite Point is a pretty unique opportunity," Barnes said. "It's relatively undeveloped. … We'll be very active out there next year. Actually we're going to fire up a drilling rig out there as well as perform some workovers and recompletions."

The offshore Trading Bay oil field has also seen success. Barnes attributed a more than 30 percent jump in oil production at this field to the knowledge and ideas of the people working on the field's monopod platform.

"Really that monopod rate jump is kudos to them," Barnes said.

Drift River terminal

In parallel with boosting production from its offshore oil fields, Hilcorp has been engaged in a major initiative to restore normal operations at the Drift River oil terminal on the west coast of the Cook Inlet. Fields such as McArthur River, Trading Bay and Granite Point export their production through the Drift River terminal, shipping the oil by tanker across to the Tesoro oil refinery at Nikiski on the Kenai Peninsula.

In 2009 the terminal's storage tanks were shut in, following an eruption of the Redoubt Volcano. The Cook Inlet pipeline carries oil from field production facilities on the west side of the inlet to Drift River — since the closure of the terminal, oil been stored at the production facilities and transported through the pipeline direct to tankers at the terminal, bypassing the terminal's storage tanks.

Inefficient

But this arrangement for exporting the oil has proved highly inefficient, with tankers being tied up for several days at the terminal before departing only half full of oil, Barnes said. As part of its restoration of the terminal, Hilcorp has spent more than $18 million raising the height of the berms that protect the tank farm from any mud flows that might come from an eruption at Redoubt.

Barnes said that there have been misconceptions about the risks associated with the proximity of the terminal to the volcano. The terminal is, in fact, 30 miles from the volcano, in a floodplain that impacts the dynamics of water flowing down the valley on the volcano's side. During the last eruption at Redoubt the berms had successfully protected the tank farm, he said.

Natural gas

Results to date from Hilcorp's Cook Inlet gas fields have been somewhat mixed. Thanks to some remedial work in the fields and some engineering ideas from town, gas production has increased from some small onshore fields on the west side of the inlet. But gas production is down 30 percent in the Hilcorp-operated Trading Bay unit in the offshore.

"That is a very difficult field to work," Barnes said, adding that Hilcorp anticipates achieving better results in this field in the future.

However, given the high rates of production decline in Cook Inlet gas fields at present, it will take much capital investment to keep production rates up.

"That's just a given right now," Barnes said, commenting that Hilcorp's preference is for 100 percent ownership of fields that it operates, to enable the company to move fast, making development decisions without the need for agreements with joint owners.

Deep Creek

In the 100-percent Hilcorp owned Deep Creek unit on the Kenai Peninsula, Hilcorp has maintained gas production at the Happy Valley gas field through the drilling of two new wells. The company is in the process of drilling a third well, a horizontal well, in the unit. The Happy Valley program involves the exploration and development of some new sand units which have not previously seen production, Barnes said. Hilcorp is planning to conduct a seismic survey around the Deep Creek unit this winter, Barnes said.

Asked if Hilcorp plans any exploration activities in the Cook Inlet basin, Barnes said that the company had entered the basin with a strategy for development rather than exploration and that, with a "full plate" of development plans, the company does not have an exploration budget for 2013. On the other hand, the basin does offer exploration opportunities and Hilcorp anticipates pursuing some of these opportunities at some point, Barnes said.

Meantime, as part of the company's gas development plans, Hilcorp has been working with Enstar Natural Gas Co. to bring Red Pad, a new gas field on the Kenai Peninsula, online by mid-December.

And moving forward into 2013, Hilcorp's strategy is to focus on its onshore properties for its gas projects.

"It's simpler to execute (than offshore)," Barnes said. "The economics are a bit better and, frankly, we think we can move the (natural gas) needle further, faster if we put our energy there."

Marathon assets

In early 2013 Hilcorp anticipates completing its purchase of Marathon's assets, following a court hearing and decision for a consent decree agreed between Hilcorp and the State of Alaska regarding the purchase of the assets. The consent decree resolves a Federal Trade Commission investigation of the purchase, Barnes said.

In terms of the business environment in the Cook Inlet basin, Barnes said that Hilcorp is emphasizing to contractors, in the habit of trying to make money fast during the booms of a boom-bust cycle, that Hilcorp anticipates operating in the region for the long term. The concept is for people to make good money steadily over the long run.

"We're going to continue, frankly, spending money and the best contractors will play, and those will be the ones that make some money," Barnes said. ●

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continued from page 1

ENERGY OUTLOOK

acter of petroleum liquids production.

"ExxonMobil projects total liquids demand to rise to 113 million barrels per day of oil equivalent in 2040, a 30 percent increase from 2010," the report says. "About 70 percent of this increase is tied to the transportation sector."

Conventional crude production will decline slightly over time, but rising production from deepwater, oil sands and tight oil resources will more than compensate.

"The successes of deepwater and oil sands developments are examples of how new technologies are key to delivering additional sources of liquid supplies to meet rising demand," the report says. "Ten years ago, these supplies were barely on the radar screen. The same is true for tight oil, which is growing as a result of recent advances in technology that have enabled the energy industry to unlock the oil found in 'tight' rock formations. The advances are very similar to the ones that have enabled the growth in 'unconventional' production of natural gas, which is also producing a rise in natural gas liquids (NGLs)."

By 2040, only about 55 percent of the world's liquid supply will come from conventional crude oil production.

"The rest will be provided by deepwater, tight oil and NGLs, as well as oil sands and biofuels," the report says.

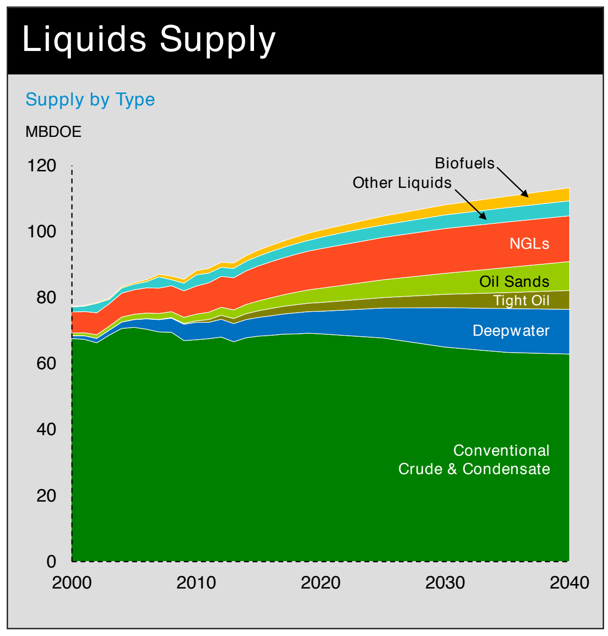
Horizontal drilling, hydraulic fracturing and other technologies have spurred major new oil production in places such as the Bakken region in North Dakota. As a result, U.S. crude production is increasing for the first time since the mid-1980s.

Around 2030, the nations of North America likely will go from a net importer to a net exporter of oil, ExxonMobil says. The Paris-based International Energy Agency, or IEA, made the same prediction in November.

Natural gas outlook

Natural gas will grow faster than any other major fuel source, with global supply to increase about 65 percent by 2040, ExxonMobil says.

In last year's energy outlook, the company predicted gas would overtake coal by 2025 to become the second most consumed fuel, after oil. The new outlook repeats that prediction.



COURTESY EXXONMOBIL

In North America, unconventional gas production is increasing rapidly, putting the continent in position to become a potential gas exporter by about 2020.

"Shale gas comprises the largest component of unconventional resources, but it also includes coal bed methane and tight gas," the report says.

ExxonMobil notes that the IEA estimates the world has about 28,000 trillion cubic feet of remaining gas resources, enough to meet current demand for more than 200 years.

"Globally, unconventional gas makes up about 40 percent of the estimated remaining resource," the report says. "In North America, unconventional gas has a higher share — accounting for about two-thirds."

Through 2040, electricity generation will account for more than half of the increase in global energy demand. And gas is primed to be a fuel of choice for making power.

Today, coal is a very competitive option for generating electricity. But natural gas becomes increasingly attractive as it emits up to 60 percent less carbon dioxide gas than coal, ExxonMobil says.

"Coal faces a significant challenge from policies to reduce greenhouse gas emissions; wind and solar face challenges related to economics and reliability considerations; and nuclear faces unique considerations regarding public perceptions of safety," the energy outlook says. "At the same time, new gas-fired generating units use very efficient technologies and are easy to build at a reasonable cost, flexible to operate and supported by abundant gas supplies. As a result, gas is increasingly viewed as the most economical fuel choice for electricity generation for the United States."

By 2040, wind energy will grow by seven times and solar power will increase by more than 20 times. But these will account for, respectively, only 7 percent and 2 percent of global electricity supply.

47 mpg by 2040

Energy demand for transportation will increase by more than 40 percent from 2010 to 2040, ExxonMobil says.

Nearly all of that growth will come from commercial transportation, rather than cars.

"In contrast to the growth in commercial transportation, fuel demand for personal vehicles — cars, SUVs and small pickup trucks — actually plateaus fairly soon and begins a gradual decline as consumers turn to smaller, lighter vehicles and technologies improve fuel efficiency," the outlook report says.

Oil is forecast to remain the predominant fuel source for transportation through 2040.

"Oil products benefit not only from the widespread availability of supplies, but also significant economic and practical advantages over alternatives," the report says. "Technological advancements are continuing to improve the fuel economy of conventional vehicles every day. In order to make a significant impact in the marketplace, alternatives like plug-in hybrids or electric cars will need to make substantial progress to overcome hurdles, including a $10,000 to $15,000 higher upfront cost plus range and functional limitations for drivers. For example, the higher energy density of oil products is such that 100 pounds of gasoline can enable a car to travel 350 miles, compared to a 100-pound battery that will power a car for only about 15 miles and can take hours to recharge."

New cars will become much more fuel efficient, averaging around 47 miles per gallon by 2040 compared to about 27 mpg today.

The outlook report is posted at www.exxonmobil.com. ●

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