Petroleum news

Vol. 14, No. 25 • www.PetroleumNews.com — A weekly oil & gas newspaper based in Anchorage, Alaska — Week of June 21, 2009 • $2

page 4 Newfoundland lands second equity deal at Hibernia South development

Shell building for Arctic


COURTESY SHELL

Shell has signed a contract for construction of a vessel to handle anchors for its Arctic offshore rig. Shown in this artist's depiction, the vessel features many environmental safeguards, is expected to provide 100 jobs. Shell said the vessel will be a centerpiece in the company's oil spill response fleet. It will house skimmers, booms and — in a worst-case scenario — hold discharge. See story, page 8.

Last single-hulled tanker leaves Alaska; Exxon's S/R Long Beach faces mandatory retirement

Has the last single-hulled tanker exited the Alaska oil trade?

The S/R Long Beach, which carried North Slope crude oil for Exxon Mobil, is "not currently physically located along the West Coast," Ray Botto, spokesman for Houston-based SeaRiver Maritime Inc., told Petroleum News on June 16.

Botto wouldn't say whether the ship will ever return to Alaska for another load of oil.

He confirmed media reports that the tanker in late April delivered a cargo of Alaska oil to the LOOP, the Louisiana Offshore Oil Port in the Gulf of Mexico. Normally, tankers in the Alaska trade carry oil from the port of Valdez to refineries in Washington state and California. Speculation was the 987-foot Long Beach could be scrapped.

Botto wouldn't confirm the ship's fate.

Mandatory retirement

The Long Beach was built in 1987 and, under the federal Oil Pollution Act of 1990 it must cease hauling oil in U.S. waters by Jan. 1, 2010, because it lacks a double hull to reduce the risk of oil spills.

A tanker listing available on the Washington State Department of Ecology's Web site shows the Long Beach is the last remaining single-hulled tanker in the Alaska trade. Fifteen other ships remain in the trade, including three more SeaRiver tankers that carry oil for Exxon. One of those, the Baytown, isn't a double-hulled ship but has a double bottom.

OPA 90, which Congress passed after the disastrous Exxon Valdez oil spill in Prince William Sound in 1989, ushered in a transformation of the Alaska tanker fleet from pre-

see TANKER page 19

BREAKING NEWS

NATURAL GAS

Who's on first?

Exxon-TransCan Alaska gas line push sends tremor through Mackenzie ranks

By GARY PARK

For Petroleum News

So ExxonMobil hitches up with TransCanada to build an Alaska natural gas pipeline.

Does that spell the end of the current road for Canada's Mackenzie Gas Project: yes or no?

Make that a definite maybe.

As opinions rolled in, there was no consensus.

Meanwhile, a separate issue is clouding the future demand for Arctic gas as North America deals with the impact on demand of gas from the continent's shale deposits.

Steve Letwin, the Houston-based executive vice president, gas transportation and international, with

see WHO? page 20

Key players in MGP

It's straightforward enough figuring out who owns what in the three anchor gas fields underpinning the Mackenzie Gas Project.

From there, the lines can get a bit tangled.

The Mackenzie Producers Group controls 5.8 trillion cubic feet of proven reserves on the Mackenzie Delta and is the driving force behind the proposal that got pulled off the shelf almost a decade ago.

Imperial Oil (owned 69.6 percent by ExxonMobil), is the lead player, with estimated marketable gas reserves of just over 3 tcf in the

see PLAYERS page 20

EXPLORATION & PRODUCTION

Investing in the Arctic

Companies must work together to conquer Far North, speakers tell OTC audience

By RAY TYSON

For Petroleum News

1 2 SERIES

No aspiring oil company can be an island when it comes to living and working in Arctic conditions, according to those in the know. So complex and formidable are the challenges that sharing information, even with competitors, is no longer an option; it's a necessity. And it's not all about technology and engineering, either, although each certainly carries its own set of challenges.

"We really need to look at the Arctic in a holistic way," ConocoPhillips chief naval architect Peter Noble told an audience at the Offshore Technology Conference in early May.

"There are a lot of issues around the environment," he explained. "There are local inhabitants that need to be considered as a high priority. They live there; it's their backyard."

Thirty years ago when Noble began working in the Arctic, "we'd say we'll find out where the ice is and we'll sail the ships there," he recalled. "The problem is those are the places where the whales are moving; it's where the migratory birds are and a lot of other things. So it's probably not a good idea to mix these. We've got to think about all of those things. There are a lot of issues and they're all interconnected."

Qualified personnel a challenge

Gary Mandel, executive vice president for big oil-

see INVESTING page 19

FINANCE & ECONOMY

China leads energy spurt

BP Review outlines unprecedented shift in global demand for fossil fuels in 2008 toward emerging nations of Asia-Pacific region; gas growth slows

By ROSE RAGSDALE

For Petroleum News

Unprecedented turbulence in world energy markets in 2008 may have overshadowed a less dramatic but perhaps equally profound development in implications for the long term.

For the first time ever, the developing world led by China leapfrogged industrial and developed nations in the consumption of primary energy.

"The centre of gravity of the global energy markets has tilted sharply and irreversibly towards the emerging nations of the world, especially China," BP Chief


TONY HAYWARD

Executive Tony Hayward said June 10 in London at the launch of the company's Statistical Review of World Energy 2009.

"This is not a temporary phenomenon but one that I believe will only increase still more over time. It will continue to affect prices and bring with it new challenges over economic growth, energy security and climate change," Hayward said.

Among those challenges will be volatility in the short term, he warned.

"But I have no doubt that the diversity and flexibility of modern energy markets will continue to ensure that energy supplies continue to reach con-

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contents

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

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 DS 13-35	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked at Deadhorse	Available
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay L3-31	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD2-74	ConocoPhillips
OIME 2000	141 (SCR/TD)	Stacked at Deadhorse	Available
TSM 7000	Arctic Fox #1	Mobilizing late June, early July to Cook Inlet for drilling at Beluga	ConocoPhillips
	Arctic Wolf #2	Mobilizing, currently in Fairbanks, will be moved to Nunivak #1, 3 miles west of Nenana next week	Rampart Energy
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 1C-07A	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay, Stacked out	BP
Mid-Continental U36A	3-S	Milne Point MPL-11	BP
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay J-21A	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay DS 18-29C	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay DS 13-03A	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)		Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Point Thompson PTU-15	ExxonMobil
Academy AC electric Canrig	105-E (SCR-TD)	Chandler #1	Anadarko
Academy AC electric Heli-Rig	106-E (SCR/TD)	Demobilization rig shut down	Chevron
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site G-16a	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site H-13	BP
Ideco 900	3 (SCR/TD)	Kuparuk, moving to 3B pad to stack out rig	ConocoPhillips
North Slope - Offshore			
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-31	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point OP04-P07	ENI
Oilwell 2000	33-E	Northstar, Stacked out	BP
Cook Inlet Basin – Onshore			
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Logging Koala 3	Aurora Gas
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Stacked	Marathon
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	Kenai SLU 41-33RD	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	Stacked, Kenai	Pioneer Natural Resources
Cook Inlet Basin – Offshore			
Chevron (Nabors Alaska Drilling labor contract)			
	428	Rig shut down by operator request	Chevron
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO
Kuukpik	5	Stacked in Kenai	Available
Mackenzie Rig Status			
Canadian Beaufort Sea			
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available
Mackenzie Delta-Onshore			
AKITA Equtak			
Modified National 370	64 (TD)	Racked in Inuvik	Available
Central Mackenzie Valley			
Akita/SAHTU			
Oilwell 500	51	Racked in Norman Wells, NT	Available

The Alaska - Mackenzie Rig Report as of June 18, 2009. 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*

	June 12	June 5	Year Ago
US	876	887	1,901
Canada	108	101	230
Gulf	46	51	68

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

● GOVERNMENT

Newfoundland lands second equity deal

By GARY PARK
For Petroleum News

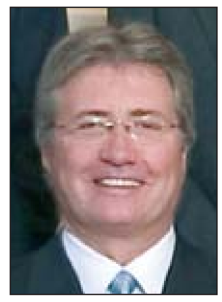
Newfoundland Premier Danny Williams carries a very self-satisfied look these days, having landed a tentative agreement that gives his province its second ownership stake in an offshore oil project.

A memorandum of understanding with partners in the Hibernia South project to develop an estimated 220 million barrels (of which 170 million barrels will be produced using a subsea tieback to the main Hibernia platform) gives the government a 10 percent equity stake for C$30 million.

Earlier industry and government forecasts have set peak production at 50,000 barrels per day after a scheduled startup in 2012.

Although a final pact will take the next few months to conclude, Williams told an industry gathering June 16 that the deal gives his government an "unprecedented royalty rate and equity interest."

He estimated the new field will generate C$10 billion over its operating life for Newfoundland, while the Canadian government will collect C$3.5 billion.


DANNY WILLIAMS

The Hibernia South partners are ExxonMobil Canada, Petro-Canada, Chevron, StatoilHydro and Nalcor Energy Oil and Gas, representing the Newfoundland government.

The Canadian government's Canada Hibernia Holding Corp. and Murphy Oil are additional partners in the existing Hibernia project.

Hibernia: 670M barrels so far

The Hibernia field has so far produced 670 million barrels since coming on stream in 1997, almost half the field's estimated 1.24 billion barrels, which includes Hibernia South.

Williams estimated his government will collect another C$13 billion from the main field now that the project has covered its capital costs and royalties are at 30 percent of net revenues.

In addition to the 10 percent stake in Hibernia South, three new super-royalty areas are covered by the memorandum of understanding — two of them carrying a top royalty rate of 50 percent when oil prices reach $70 per barrel WTI and 42.5 percent for a third license area.

The Newfoundland government sidetracked plans for Hibernia South in January 2007, including regulatory approval, as Williams waged a battle with the industry over his determination to secure a 10 percent equity stake in all new and expanded offshore projects.

As well, he wanted a more robust development program and information on future plans to develop stranded natural gas reserves in the oil fields.

Williams achieved his major breakthrough with the revival of the Hebron project by securing a 4.9 percent government equity stake.

There has been a growing sense of urgency to settle the government-industry differences because of estimates that the three operating projects are headed for a 21 percent decline in total production this year to 98.5 million barrels, slipping to 84 million barrels in 2011.●

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● LAND & LEASING

TG World opposes Beechey Point unit

Calgary independent says proposed unit shortchanges its interests, has multiple operating agreements that invite waste, inequity

By WESLEY LOY
For Petroleum News

TG World Energy Inc. is objecting to the proposed formation of the Beechey Point unit on the North Slope, saying its partners submitted faulty information that denies the Calgary-based independent oil and gas company's interest in leases.

"Despite expending hundreds of thousands of dollars in acquiring lease interests and even more in preparatory expenses for the unit, over half of TG's interests in the proposed unit are not reflected in the application," lawyers for TG World wrote in comments submitted to the Alaska Division of Oil and Gas on June 8.

Brooks Range Petroleum Corp. of Anchorage applied for formation of the Beechey Point unit on April 27. The unit encompasses 25 state leases totaling 52,877 acres, and is situated in the Gwydyr Bay region adjacent to the Prudhoe Bay and Northstar units.

Brooks Range is operator for the unit. Its parent company, AVCG of Kansas, is a partner with TG World and two other companies in a North Slope oil and gas exploration and development joint venture.

But relations are strained between Brooks Range and TG World, which have sued one another in Alaska Superior Court alleging contract breaches.

TG World did not sign the Beechey Point unit application. Its lawyers say the company is not opposed to the state approving the unit formation, but it first wants a few problems to be cured.

Three objections

First, TG World contends the application incorrectly shows AVCG as 100 percent working interest owner in 12 leases listed on the unit application "when in fact TG paid to acquire a 35 percent interest in those leases." In its filing to the state, TG World cites payments of at least $293,950 to secure the lease interests.

Second, TG World says the Brooks Range unit application lacks "a single signed unit operating agreement covering the entire unit area." Rather, the company contends Brooks Range has submitted four separate operating agreements covering the Beechey Point unit.

"Importantly, the separate operating agreements do not apply to different geologic regions or formations with the proposed unit," TG World told the state. "Rather, two of the operating agreements overlap completely and attempt to cover the same area under different terms and conditions, while the remaining two attempt simultaneously to cover one of the

see OPPOSITION page 17

NATURAL GAS

In-state gas feasibility study begins

Legislators get update from Harry Noah, governor's in-state gas coordinator; contract let to engineering firm Michael Baker Engineers

By KRISTEN NELSON
Petroleum News

Harry Noah, the governor's in-state gas coordinator, updated legislators June 5 on the work plan his office is doing on in-state natural gas.

Noah said the underlying problem is that Alaska has "no clear source of long-term affordable fuel."

This program, he said, is focused on development of the state's natural gas resources with the intent of providing legislators, the governor and the public with enough information "in terms of costs associated with this and the risks associated with this that the long-lead-time public policy decisions could be made."

There are three questions that need to be answered about gas development for in-state use, he said:

"Can a standalone project from the North Slope to Cook Inlet be commercially viable?"

Would it make more sense for the state to provide incentives for development of additional Cook Inlet natural gas as opposed to bringing gas from the North Slope to Cook Inlet?

A spur line to Southcentral off a gas pipeline taking North Slope natural gas to market has been on the table for a long time, Noah said, and the question there is, "What are the actual savings associated with that, if we wait for that pipeline?"

There are five major tasks: a feasibility study on a standalone project; taking gas to western Alaska; whether it makes sense to provide incentives for Cook Inlet gas development; defining cost-of-service comparisons between a standalone line and a spur line; and permitting work for a standalone project so it can move forward rapidly if it is feasible.

The timeframe for the first four items is June of 2010, he said, and getting the work done will involve a technical team and a commercial working group.

The state's goal with the permits — and the feasibility study — is to package them and put them out for bid for anyone that might want to build the pipeline, Noah said.

Four contracts

On the technical side an engineering contract has been let to Michael Baker Jr. for engineering, he said, introducing Keith Meyer, Mike Metz and Ward Whitmore of that firm. Bids have been received back on a second contract for an environmental contractor to support the permitting. The third contract will be for help in looking at the Cook Inlet gas basin question. And then a third-party contractor to do an environmental impact statement.

On the commercial side a commercial working group has been formed including companies who have natural gas and companies who need to buy it.

"We have invited Anadarko, Exxon, BP, Conoco, Agrium, Enstar and the Railbelt utilities, specifically Chugach and Golden Valley, to participate as a group in helping us define this project."

Noah said the pipeline is important, "but the most important thing is to answer the question: The people that are producing the gas — are they willing to sell it to the people that want to buy gas and vice versa?"

"This is the critical commercial question that has to be answered here," he said.

The state is just a facilitator; the potential sellers and buyers are the key, Noah said, "and they've all committed to step up to the table and work on the project."

The first commercial meeting will be in about two weeks, he said.

Noah said there are two important points on the commercial side. Major industrial users are necessary to hold down costs to consumers on an in-state gas line, "whether it's a standalone project or it's a spur line." The second point is that time is an issue — one of those potential industrial users, the Agrium fertilizer plant, is already shut down and at some point that plant will "age and rust and blow away."

If industrial customers aren't available the state could subsidize an in-state line, Noah said, telling legislators "that will be for you all to decide, but if you want a commercial project then you've got to have the big industrial users."

Feasibility study

Keith Meyer, a pipeline engineer with Michael Baker, briefed legislators on the feasibility study for a standalone project to transport natural gas from the North Slope. This would include a conditioning plant on the North Slope, defining the route and the gas demand, Meyer said.

The assumption on gas demand is going to be about half a billion cubic feet a day, he said, because the project won't make sense unless you have enough volume to make economic sense.

He said they don't see a demand for gas in-state greater than 500 million cubic feet a day, and are looking at 460 million to 480 million cubic feet a day.

The base case is a 24-inch-diameter line which could actually carry up to 1.3 billion cubic feet a day, he said, but the numbers they put together will indicate whether a 24-inch line is needed or a 20-inch line.

Those things — a gas conditioning plant, the transportation and the gas demand — will be put together to figure out the cost of service. That doesn't include the cost of gas, he said: It's just putting in the gas conditioning plant and transporting the gas to the customer.

What's included in a gas conditioning plant depends a little on the composition of the gas, Meyer said: If extra components are added to the methane, additional things will have to be done at the gas conditioning plant. If the gas is "spiked" by adding some liquid components, the pressure in the gas pipeline might also have to be raised to ensure those liquids don't drop out in the line.

Routing issues include pinch points, such as Atigun Pass, and the Parks and Richardson highways routing alternatives.

He said they hope there will be natural gas liquids plant opportunities and the feasibility study will look at whether an NGL plant could profitably be put in Interior Alaska and whether utilities can use NGLs.

Will draw on other work

Meyer said there has been a lot of work done on the trans-Alaska oil pipeline corridor and they'll draw on that.

The Alaska Natural Gas Development Authority has done economic studies they'll draw on, he said, and Enstar Natural Gas Co. has done route studies and an agreement is in the works to share data with Enstar.

The Department of Natural Resources and the Department of Revenue have done tariff models and they "expect to supply cost elements to the DNR and DOR and have them supply the actual tariff element," Meyer said.

The Department of Transportation and Public Facilities has done route studies and there is also a wealth of information available from groups such as the Joint Pipeline Office and the U.S. Geological Survey.

Gas to western Alaska

Meyer said that getting natural gas to western Alaska isn't an issue of trying to sell western Alaska gas at the price gas would sell for in Anchorage, but "trying to get gas to them at something that would be economic to their other alternatives."

What they'll be looking at is how to get gas to Donlin Creek, which would be a big user, Meyer said, but the study won't include how that gas could be distributed to the region. The focus will be "can we get it there and get it there at a reasonable price," he said.

The Cook Inlet study will include answering questions about how much land is actually available for exploration; what would be the estimated cost of exploring for and producing new gas and if new discoveries were made how long it would take to get those discoveries into production, particularly if they were offshore.

Answers to those questions lead to the question of what it would take in terms of incentives for new exploration to occur, and Noah said that is really an issue for DNR and the Legislature. ●

SAFETY & ENVIRONMENT

Canada unveils carbon trading plans

Market could start operations later this year; environment minister hopes domestic market will grow into North American version

By GARY PARK

For Petroleum News

The Canadian government has taken its long-delayed step towards carbon trading that it hopes will lead to a North American marketplace embracing the United States and Mexico.

Environment Minister Jim Prentice released draft rules for a federal carbon-offset scheme, including which projects will qualify, how others can apply for inclusion, the value of each offset credit and how reductions in greenhouse gas emissions will be tracked and verified.

He said the initiative contains an option for large industries, which account for 30 percent of total Canadian GHGs, to comply with mandatory emissions cuts the government plans to unveil later this year.

"The offset system, like all elements of our climate-change plan, is aimed first and foremost at reducing emissions in Canada," he said. "We will be rigorous in ensuring that credits will only be issued for projects that actually reduce the amount of GHGs in this country."

Dealing indirectly with concerns over the complexity of carbon trading and the risks of fraud occurring, Prentice said "this is not about creating an abstract world where 'paper credits' are bought and sold like some complex financial product."

JIM PRENTICE

"Every offset credit will represent a real and verifiable emissions reduction equal to the equivalent of (one metric ton) of carbon dioxide.

"What I'm describing is a gold standard of offset credits that will apply in Canada," he said.

Looking for trading market

Prentice said he is counting on the United States adopting a cap-and-trade system that will allow Canada and the U.S. along with Mexico, to establish a common trading market.

"Clearly the United States is headed in the direction of a marketplace," he said. "We have a very close dialogue with the United States on this issue."

But Prentice emphasized that traders, not the government will establish a price for carbon in Canada.

"We will be rigorous in ensuring that credits will only be issued for projects that actually reduce the amount of GHGs in this country."

—Canadian Environment Minister Jim Prentice

More elements of Canada's climate change regulations, including GHG reduction standards for each industry, will be released by December before the Copenhagen summit on a post-Kyoto United Nations climate change treaty.

He said Canada's final package of climate change regulations will be released in 2010 and start to take effect in 2011, although, depending on the response to the latest proposal, carbon trading could start later this year. However, only carbon offsets made after Jan. 1, 2011, will count toward the reduction targets that industry will be required to meet.

Canada's goal is a 20 percent reduction from 2006 GHG levels by 2020 and 60-70 percent by 2050.

Complement to regional markets

Prentice said the federal offset system will "complement, not supplant" a patchwork of regional carbon markets being developed by Ontario, Quebec, British Columbia and Manitoba.

Those schemes have been launched by provinces which have grown frustrated with waiting for a national or continental market, notably the Western Climate Initiative, which is a coalition of four Canadian provinces and seven U.S. states that is developing a regional market to trade carbon emissions.

A spokesman for the Canadian Association of Petroleum Producers said there is nothing in the draft rules that is unexpected, but the industry will take the 60-day response period to provide "appropriate and constructive feedback."

He said the government has taken a "good step towards a broadly applicable climate policy for Canada."

Gary Leach, executive director of the Small Explorers and Producers Association of Canada, welcomed the government's efforts to harmonize its approach with the provinces, thus preventing competing and inconsistent federal and provincial schemes.

He said his association favors the Alberta approach which targets large emitters and puts an emphasis on funding the research and development of new technologies.

Will emissions just be moved

Matthew Bramley, director of the Pembina Institute's climate change program, said he is concerned that the federal offset system will only "move emissions around," not reduce them.

Alberta Premier Ed Stelmach said he had already urged Prentice not to place an unfair burden on Alberta, which is generating wealth to support the rest of Canada, and not to get too far ahead of the United States.

Alberta Environment Minister Rob Renner said his government will now lobby for a federal fund to complement the trading system by promoting the development of carbon capture and storage.

However, Prentice said earlier in June that he does not see CCS as the "silver bullet" for lowering GHGs in the mining and in-situ extraction of oil sands bitumen.

He said CCS is "important, but it's really in the upgrading of bitumen that CCS has more promise."

The Alberta government is expected later in June to allocate money from its C$2 billion fund to support the development and testing of three to five CCS projects from 11 applications.

ConocoPhillips has pulled out of that competition, estimating it would cost more than C$200 per metric ton to capture and sequester carbon dioxide from its Surmont oil sands operation, compared with estimates of C$15-$30 a metric ton for trading carbon on open markets.

The company's outgoing Canadian President Kevin Meyers told reporters that the C$200 estimate does not apply to all potential CCS projects and should not be viewed as a blanket rejection of CCS. ●

● NATURAL GAS

TransCanada-Exxon plan has Thomson line

ExxonMobil to lead integrated Alaska pipeline project team; TransCanada will keep Alaska technical lead through open season

By KRISTEN NELSON

Petroleum News

While TransCanada will head the management committee for the joint TransCanada-ExxonMobil Alaska pipeline project announced June 11, ExxonMobil will lead the integrated project team.

"During its development and construction, the Joint Project is managed within an integrated project organization, led by ExxonMobil," the companies said in a work program and budget submitted to the State of Alaska. The development phase includes work through receipt of a certificate from the Federal Energy Regulatory Commission in mid-2014; then the construction phase begins and continues through initial gas in the fall of 2018.

When ExxonMobil's partnership in the TransCanada project the state licensed under the Alaska Gasline Inducement Act was announced, ownership shares were not made public, but the companies said TransCanada retains majority ownership.

The AGIA license provides up to $500 million in state matching funds for specified work by the licensee and other incentives in exchange for a commitment to meet certain state requirements for the North Slope-to-market gas pipeline project, and to complete work through receipt of a certificate of convenience and necessity from FERC.

While ExxonMobil will lead the integrated project team, TransCanada will have a somewhat broader role in the joint current proposal subphase, which continues through to July 30, 2010, when the open season process ends. In addition to leading the pipeline and compression sub-project in Canada, TransCanada's role during the current phase "is expanded to include the technical work associated with the pipeline and compression system downstream of the GTP in Alaska," the companies said.

Point Thomson line included

The plan TransCanada and ExxonMobil submitted to the State of Alaska for their joint work includes a gas treatment plant on the North Slope, a gas pipeline to market in either Alberta or Valdez or both — and a gas transmission line from Point Thomson to the GTP.

Because the line from Point Thomson to the gas treatment plant is not part of AGIA, costs for that portion of the work are not reimbursable by Alaska under AGIA, the companies said.

On the Web

See previous Petroleum News coverage:

"Exxon joins line," in June 14, 2009, issue at www.petroleumnews.com/pnads/431642295.shtml

ExxonMobil is one of the three major gas owners at Prudhoe Bay, but is also the major owner at Point Thomson, and its combined ownership in the two fields makes it the largest owner of known North Slope natural gas reserves.

The joint work plan is not a commitment to build a gas project from Alaska's North Slope to market, but does commit to work that will be done through an open season. The companies said subsequent work plans will cover the work involved in submitting a certificate of convenience and necessity to FERC and then getting approval from FERC for that certificate.

BP and ConocoPhillips — the other major North Slope gas producers — are also progressing a gas pipeline project, Denali, from the North Slope to North American markets.

Only one project will be built and there is general agreement that it will require collaboration among TransCanada, the pipeline company; the State of Alaska; the three major North Slope gas owners; and U.S. and Canadian governments.

Definition before decision

The current phase of the project — through July 30, 2010, the end of the open season process — is the proposal sub-phase of the development portion of the project.

Benchmarks in the current work include:

- May 5, 2009, commencement of joint work;
- March 31, 2010, capital cost estimate complete;
- March 31, 2010, FERC approval of open season plan; and
- July 30, 2010, open season complete.

Two definition phases will occur before a decision is made to proceed with

Because the line from Point Thomson to the gas treatment plant is not part of AGIA, costs for that portion of the work are not reimbursable by Alaska under AGIA, the companies said.

construction, the companies said in paperwork filed with the state and available on the state's AGIA Web site at www.gov.state.ak.us/agia/agia_tc-em.php: definition sub-phase one with the primary focus on preparing and filing an application for a certificate of public convenience and necessity with FERC and related regulatory applications in Canada; definition subphase two with primary joint work focus on securing the FERC certificate and the Canadian leave to proceed, securing project financing and preparing for the decision to proceed.

According to project milestones, definition subphase one would end in October 2012 with filing of the FERC application; definition subphase two would end June 2014 with issuance of the FERC certificate in the U.S. and the leave to construct by the Northern Pipeline Agency in Canada.

Pre-construction logistics would begin in May 2016; on-site construction in April 2016; initial gas deliveries in September 2018.

Greenfield v. brownfield

The companies said there will be 90 full-time-equivalent members of the project team staff, including employees, secondees and in-house consultants; the budget for work from May 5 through July 30, 2010, is $141,996,000. There will be field offices for the project in Anchorage and Whitehorse, Yukon.

In discussing the scope of gas treatment plant work the companies said this phase is concept selection and scope definition, with definition leveraging the Alaska Gas Producers Pipeline Team study, a BP-Conoco-Exxon study done early in the decade.

The scope includes determination of a greenfield vs. brownfield development, i.e. the extent to which a GTP could be integrated with the existing Prudhoe Bay Central Compressor Plant and Central Gas Facility. AGPPT studies will be used to develop a greenfield standalone GTP as a base case, the companies said.

The GTP work will also include a review of carbon dioxide disposal requirements and how those could be integrated into existing operations. The companies said the current base case includes CO_2 re-injection into Prudhoe Bay reservoirs.

On the pipeline side, a winter field program was to be completed this spring and a summer field program is planned including a geophysical investigation program and a supplemental borehole drilling program.

Alaska legislators have scheduled hearings June 23 to hear from all the pipeline proponents and the administration. ●

EXPLORATION & PRODUCTION

New ship to support Shell drilling

Edison Chouest vessel to handle anchors for Arctic offshore rig, provide 100 jobs, feature many environmental safeguards

By WESLEY LOY
For Petroleum News

Because of pending court challenges, Shell is having a heck of a time getting its offshore drilling campaign under way in the Arctic Ocean off Alaska.

But the company continues making big investments for the day its drill bits start turning.

The latest example is a contract for construction of a powerful boat designed to handle the anchors of offshore drilling platforms in the icy Beaufort and Chukchi seas, where Shell has dropped billions of dollars on federal oil and gas leases.

The new boat, not yet under construction, doesn't have a name at this point, just a number — hull number 247.

Once built — about a two-year job — the boat will be one of the most advanced and environmentally sound anchor-handling tug supply vessels ever launched for work in the Arctic, said managers for Shell and for the builder.

"It'll be the pride vessel of our company," said Capt. Michael Terminel, Alaska operations chief for Edison Chouest Offshore, the Louisiana firm that will build and run the 247 under long-term charter to Shell.

Navigating the law

Construction of the new anchor handler will help Shell better cope with federal law pertaining to commercial ships working in U.S. waters.

When Shell first planned to drill in the Beaufort Sea in the summer of 2007, it brought in foreign-flagged anchor handlers to support two offshore drilling platforms.

Normally, foreign vessels can't work between U.S. ports — or between a port and an offshore drilling rig — under what's known as the Jones Act.

Congress, however, wrote a temporary exception into the Safe Port Act of 2006, which said an oil company may use a foreign-flagged vessel "for the setting, relocation, or recovery of anchors or other mooring equipment of a mobile offshore drilling unit" on the Outer Continental Shelf in the Beaufort or Chukchi seas.

The exemption potentially is available through 2011, enough time for Shell to construct something in very short supply: an American-built anchor handler fit for work in the Arctic, said Rick Fox, a Shell manager in Anchorage.

Speaking at a recent meeting of the Alaska Oil and Gas Association, Fox said the 247 is a $150 million project.

"Certainly this shows our commitment to investing in the Arctic," Fox told Petroleum News on June 15.

COURTESY SHELL

Some boat

The 247 will perform a key job — managing the heavy anchors and mooring lines of Shell's drilling platform. It's a job that requires a lot of lifting horsepower and constant vigilance, especially amid the shifting ice of the Arctic Ocean.

Because the boat will be a qualified Jones Act vessel, it will offer more versatility than foreign-flagged craft because it can be used to haul supplies between U.S. ports and the rig, said Kate Miner, head of logistics for Shell in Alaska.

Under the latest plans Shell has submitted to industry regulators, it aims to use a drillship to bore one exploratory well in the Beaufort Sea next year, followed by a single well in the Chukchi Sea, also in 2010. The drillship, the Frontier Discoverer, currently is working in the South China Sea, Fox said.

According to an Edison Chouest specification sheet, the 247 will be 342 feet long with "capability to break level, first-year sheet ice of a nominal thickness." The vessel will have 64 bunks, a deck for landing a Sikorsky S-92 or similar-sized helicopter, four Caterpillar C280-12 diesel engines and two propellers.

For lifting, the vessel will have winches that are stronger than necessary for the relatively shallow waters of the Beaufort and Chukchi. Fox said that will give the boat the ability to compete for jobs elsewhere in the world such as the deepwater Gulf of Mexico, where both Shell and Edison Chouest are very active.

Not least is the 247's many environmental features to reduce nitrogen oxide emissions, minimize noise that can disturb marine mammals and prevent leaks and spills. The vessel will be double-hulled, and the hull will be painted a cool blue at the request of North Slope subsistence hunters who believe louder colors such as orange can scare away whales, Fox said.

Chouest in Alaska

Edison Chouest (pronounced shwest) is a global builder and operator of industrial work boats and research vessels. Founded in Galliano, La., in 1960, the company touts itself as "the most technologically advanced and fastest-growing offshore vessel service company in the

see SHIP page 11

SAFETY & ENVIRONMENT

Snag in fuel recovery from M/V Monarch

PETROLEUM NEWS

Planned fuel recovery from the sunken supply vessel Monarch in Cook Inlet was unsuccessful June 13 when the mooring system on the Ocean Marine Services Inc. vessel Perseverance failed.

The Alaska Department of Environmental Conservation said in a June 15 situation report that the OSV Perseverance arrived at the Granite Point platform June 12 to begin fuel recovery and three dives were accomplished during slack tides beginning early in the morning June 13.

On the Web

See previous Petroleum News coverage:

"Fuel to be recovered from sunken vessel," in June 14, 2009, issue at www.petroleumnews.com/pnads/984402662.shtml

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

The OSV Perseverance at the Granite Point platform in Cook Inlet

DEC's Division of Spill Prevention and Response said divers established a locate line to the Monarch, which sank Jan. 15 when it was pinned against the Granite Point platform by sea ice while making a delivery; the Monarch's seven-member crew evacuated to the platform. The Monarch, now on the bottom of Cook Inlet near the platform, carried some 34,000 gallons of diesel fuel, 690 gallons of lube oil and totes and drums of chemicals for delivery to platforms.

The divers cleared debris around the fuel tank access cover, removed the deck cover on the port number one fuel tank, inserted a 2-inch flexible wand through the deck opening to the top of the fuel tank and began fuel recovery operations.

950 gallons of diesel recovered

Some 1,250 gallons of fluids were recovered on the fourth dive — 950 gallons of diesel fuel and the remainder seawater.

But the evening of June 13 the mooring system holding the Perseverance in place failed in an estimated 4 knots of flood tide current.

Perseverance established position on the east side of the Granite Point platform, awaited slack current and safely recovered the mooring system and disconnected from the platform; the vessel then departed for Nikiski Bay.

The division said unified command meetings on June 13 and 14 determined that recovery operations would discontinue due to safety and engineering concerns.

Ocean Marine Services is examining all options, including a stronger mooring system and replacing the 207-foot Perseverance, which displaces 2,158 tons and draws 15 feet of water, the division said. The vessel's deep draft makes it more susceptible to current forces. ●

Petroleum News Maple Leafs

News Briefs from Canada

Don't bet on $70 lasting

Export Development Canada, a federal government financing agency, has nudged its forecast 2009 average price for West Texas Intermediate crude to US$55 a barrel from an earlier $47, rating $70 as unsustainable based on demand fundamentals.

The agency's chief economist Peter Hall said hints of economic recovery over the past month forced an adjustment in the agency's target price, but there is still no reason to count on a return to $100 oil in the near future.

He said there is "so much inventory" on the world market that a $70 price is not likely to last over a prolonged period, although demand during the peak driving season is difficult to estimate.

—GARY PARK

Environmental plea rejected

Alberta's Energy Resources Conservation Board and the Canadian government have turned down demands from an environmental coalition to reopen their approval of a C$13.7 billion expansion of a Royal Dutch Shell oil sands project.

The board said the request did not include sufficient evidence to warrant a new public hearing, while federal Environment Minister Jim Prentice said he did not have the statutory power to reconvene an assessment review panel.

The Oil Sands Environmental Coalition — including the Pembina Institute, the Toxics Watch Society of Alberta and the Fort McMurray Environmental Association — said Shell had broken a negotiated agreement to significantly cut the output of greenhouse gases from additions to its Muskeg River and Jackpine bitumen mines.

The group claimed Shell had scrapped a pledge to set specific targets for emissions cuts, saying it would wait for the Canadian government to produce its own emissions regulations.

Shell said it would work with stakeholders to strengthen carbon dioxide emissions standards, but needed the government to establish the rules rather than relying on voluntary commitments.

—GARY PARK

Challenged by gas imbalance

Canada's junior- and intermediate-sized conventional oil and gas producers are tilting too much towards natural gas, given the fact that gas is severely underperforming in the current market, said research firm Bryan Mills Iradesso.

In its first-quarter report covering 63 juniors (which produce less than 10,000 barrels of oil equivalent per day) and 23 intermediates (producing 10,000-100,000 boe per day), the firm said the median intermediate's production is weighted 67 percent to gas and the median junior is at 76 percent.

"Given that oil sells for much higher prices … this weighting is a challenge to the industry," the survey showed.

In both categories, it said companies have increased their gas weighting by about 5 percentage points since the same quarter of 2008.

Bryan Mills Iradesso said that only six of the junior companies had positive earnings in the opening quarter and seven reported negative cash flow, while 10 of the intermediates had positive earnings.

It said that was a sign that the costs of Canadian oil and gas production, when taking into account finding, development and acquisition costs that are written down over time, "are generally too high for the revenue currently being brought in."

The report said the median cash flow netbacks for the quarter were C$11.85 per boe for juniors and C$20.43 for intermediates, compared with C$28.33 and C$30.06, respectively, a year earlier.

It noted that the discrepancy between juniors and intermediates was related to hedging programs in place for most of the intermediates.

With low cash flow netbacks, the median junior was trading at a reasonable enterprise value of 8.3 times first-quarter cash flow, while the median intermediate was 7.3 times cash flow.

—GARY PARK

● LAND & LEASING

State seeks to intervene in OCS litigation

By KRISTEN NELSON
Petroleum News

Newly appointed Alaska Attorney General Dan Sullivan has moved to intervene in a federal case in which the Native Village of Point Hope is asking the courts to rescind leases issued by the U.S. Minerals Management Service in the Chukchi Sea.

"One of my highest priorities as Alaska's attorney general is to vigilantly safeguard and defend Alaska's interests, particularly as they relate to economic opportunities for Alaskans and the balance of state and federal rights and responsibilities. This case entails both such interests," Sullivan said in a June 17 statement.

"The ultimate outcome of this case will likely have enormous economic consequences — either positive or negative — for the State of Alaska and our citizens," said Gov. Sarah Palin. The United States Court of Appeals for the District of Columbia upheld an appeal against the MMS 2007 to 2017 outer continental shelf lease sales by the Native Village of Point Hope and several environmental organizations on April 17.

On May 11 Secretary of the Interior Ken Salazar asked the U.S. Department of Justice to seek clarification from the court regarding the status of leases already issued under the lease sale program.

Sales already held under the 2007-12 program include the February 2008 Chukchi Sea lease sale and three lease sales in the Gulf of Mexico.

Focus on Alaska

In a May 28 filing the petitioners in the consolidated case — Center for Biological Diversity, Native Village of Point Hope, Alaska Wilderness League and Pacific Environment — said that vacating the leasing program, or at least those portions of it in Alaska, "is a critical component of the remedy in this case."

Plaintiffs said they would not oppose a clarification of the court's authority to vacate lease sales which applied to only the Beaufort, Chukchi and Bering seas program areas, removing scheduled lease sales from the program and voiding leases from sale 193 in the Chukchi.

Plaintiffs told the court that vacating the existing program ensures that the Department of Interior starts with a clean slate in upholding the public interest in the environment and removes the danger that the agency is so committed to a particular result that it resists genuine reconsideration of the issues.

"Here, once companies have bid on and paid Interior for leases, Interior will be much less likely to reverse course

see OCS LITIGATION page 15

● FINANCE & ECONOMY

High court strikes down Valdez tanker tax

Tax imposed on tankers in 2000 found unconstitutional by U.S. Supreme Court; Alaska Supreme Court had ruled in favor of tax

THE ASSOCIATED PRESS

The U.S. Supreme Court on June 15 struck down as unconstitutional a tax that the city of Valdez imposed on oil tankers loading crude oil from the southern terminus of the 800-mile trans-Alaska pipeline.

The court ruled 7-2 that the city has been unfairly taxing tankers that use its port as they load up with crude bound for West Coast refineries.

The city argued that the tax, imposed in 2000, was an unremarkable property tax, and that the tankers and their crews were being taxed for municipal services they use in Valdez.

The 4,500 residents of Valdez rely on the money to pay for government services and schools.

City manager John Hozey said $8 million was budgeted for revenue from the tax in the 2009 budget.

"We're still trying to determine what this is going to mean for the city and what our options are," Hozey said.

Polar Tankers Inc., a subsidiary of Houston-based ConocoPhillips and operator of five double-hulled tankers, challenged the tax in the U.S Supreme Court after the Alaska Supreme Court ruled in favor of Valdez.

"We're pleased we did get the opportunity for a fair and impartial review of our arguments before the U.S. Supreme Court," ConocoPhillips spokesman Bill Stephens said. "In that court, seven justices agree that Valdez's tanker tax is unconstitutional."

Other shippers paying

Tanker operators such as BP, ExxonMobil and Tesoro already have long-term settlements on the tax with Valdez.

"The agreements we had with other tanker companies were still valid up until this point. But going forward, now we have to account for the Supreme Court decision," Hozey said.

ConocoPhillips has paid the tax under protest for several years while pushing legal arguments to kill it.

Justice Stephen Breyer, in his majority opinion, said the tax violates the Constitution's "tonnage clause" — one of several provisions intended to foster free trade.

The town started taxing tankers and other large vessels in 2000 so it could offset declining property tax revenue from depreciating Alyeska Pipeline Service Co.'s oil storage and loading complex.

Lawyers for Polar Tankers argued against the tax on several constitutional and fairness grounds, including a violation of the "tonnage clause," which the company has said bars state and local governments from taxing the privilege of using ports and harbors.

Polar also said the tax was discriminatory because it was targeted at essentially one vessel type, oil tankers, and escort vessels. It exempted large commercial fishing boats.

Lawyers for the city had argued the tax does not violate the tonnage clause because it is not truly a tonnage duty, which taxes vessels, based on its tonnage, for entering or leaving a port.

The city's lawyers contend the tax is "an unremarkable property tax," and is based on the vessel's market value. It's tempered and in line with the number of days the ship spends in port, according to city lawyers.

They claim the tax to be minor because Polar Tankers have paid "well under $2 million in the tax years at issue on vessels worth hundreds of millions of dollars, carrying cargo worth billions of dollars."

The case is Polar Tankers v. City of Valdez, 08-310. ●

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SHIP

world."

Chouest has established a considerable presence in Alaska. Two years ago it built the Nanuq, a 300-foot oil spill response boat for Shell's Arctic exploration. That vessel is now working for a different company in Trinidad pending the start of drilling in the Beaufort and Chukchi, Terminel said.

Another Chouest boat, the 279-foot anchor handler Dove, in early 2007 towed the huge X-band offshore radar platform from Pearl Harbor, Hawaii, to Adak in the Aleutian Islands. The radar is part of the U.S. missile defense program.

Chouest also is partners with Fairweather International Inc. on the Deadhorse Aviation Center on the North Slope.

Terminel, a veteran of numerous icebreaker expeditions to Antarctica, said no company is better suited for work in the Arctic than Chouest. The 247, he said, will provide around 100 jobs.

"We're really pushing hard to crew it with Alaskans," Terminel said. ●

NATURAL GAS

Private sector lead sought for propane

ANGDA hosts Alaska Propane Opportunities Conference; state corporation looking for companies to process, transport, buy propane

By STEFAN MILKOWSKI
For Petroleum News

The Alaska Natural Gas Development Authority has reached a tentative agreement with a major North Slope producer for the sale of propane and is seeking private parties to help distribute the fuel across Alaska.

At a conference June 17 in Fairbanks, ANGDA Chief Executive Officer Harold Heinze urged anyone interested in processing, transporting, or buying propane to come forward now to help make the project a reality.

"We believe it's got every basis in the world to go forward," he said, "but it's not what I think; it's what you think, that in the ultimate is going to count here."

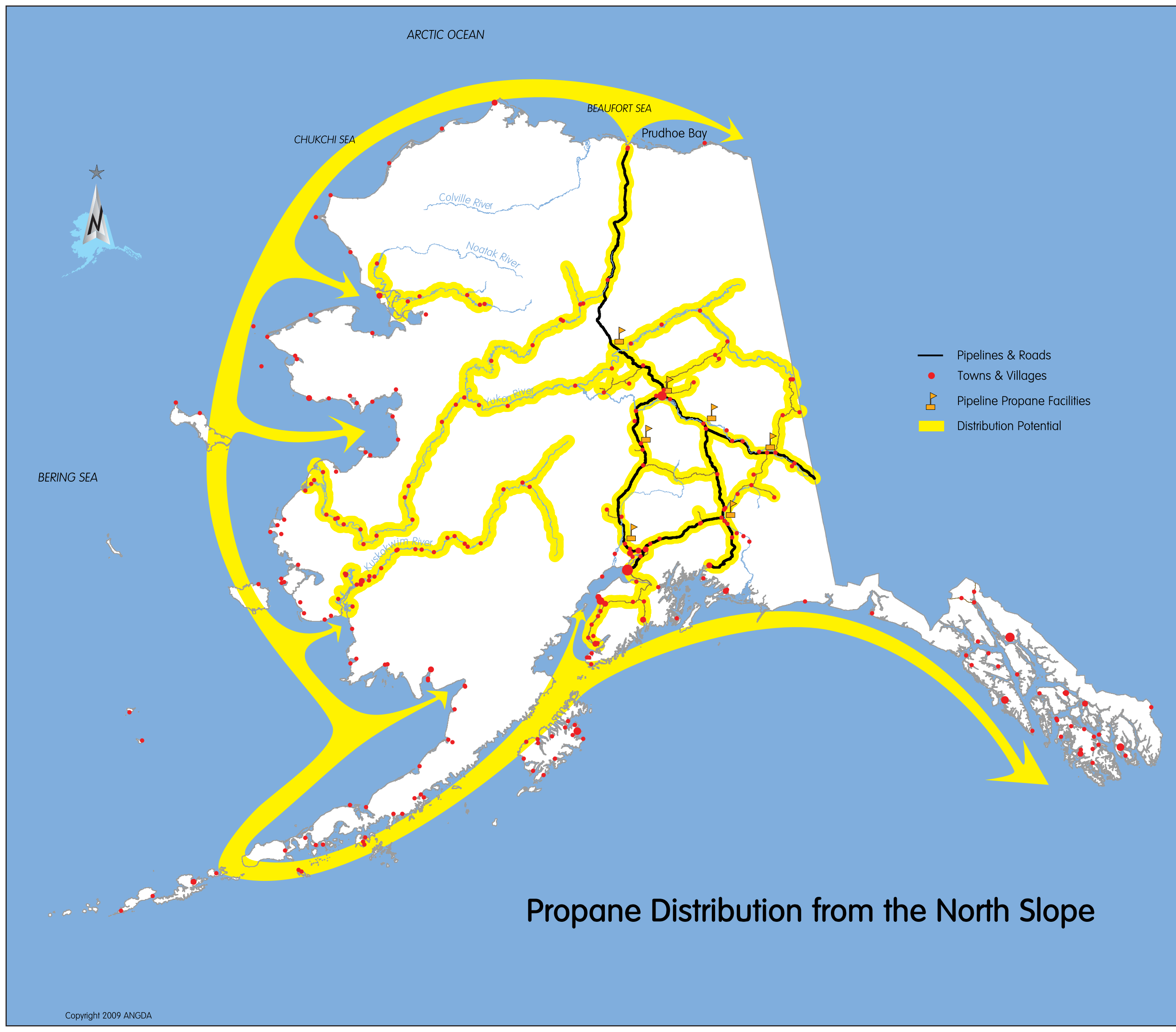
If the private sector isn't interested in the project, Heinze said, ANGDA will "write it off as another good idea that didn't launch."

ANGDA's idea is to draw several thousand barrels per day of propane out of the stream of natural gas produced at Prudhoe Bay at one or more propane extraction plants. Gas would be returned to existing processing facilities and reinjected into the ground. Prudhoe Bay natural gas contains about 2 percent propane, according to Heinze.

The propane would then be processed and transported by truck and barge to cities, villages and large industrial users around the state. ANGDA would help develop the North Slope infrastructure and ensure that gas is available to all interested parties, while private entities would operate the infrastructure and deliver the propane.

Heinze said one of the three major North Slope producers has agreed to sell propane for a small fraction of the cost of oil — as little as 20 to 30 cents per gallon of propane — if an independent third party can prove the project is technically feasible and if there's a market for the gas. (Heinze said the producer doesn't want to publicly announce a major project that goes nowhere.)

ANGDA has contracted with the firm NANA Worley Parsons to study whether



ALASKA NATURAL GAS DEVELOPMENT AUTHORITY

the project is technically feasible and is talking with large energy consumers like Golden Valley Electric Association in Fairbanks and the Red Dog mine near Kotzebue to ensure a market for the gas.

According to an analysis by Scott Goldsmith of the Institute of Social and Economic Research, extracting the propane and shipping it to Fairbanks would add roughly a dollar per gallon in cost. On a per-Btu basis, propane would be cheaper than heating oil any time North Slope oil was selling for more than $21 a barrel, he said. At current oil prices, customers would save more than $17 million a year by substituting 2,000 barrels per day of propane for heating fuel.

Mary Ann Pease, ANGDA's propane supply coordinator, said propane deliveries could begin within two years.

Making it work

Sales of propane in Alaska currently amount to roughly 1,000 barrels per day, according to the American Petroleum Institute. Propane is supplied by the Tesoro refinery in Kenai and by imports from Canada and the Lower 48.

ANGDA's proposal envisions anywhere from 1,000 to 10,000 barrels per day of propane from the North Slope, although Heinze said the project would probably need at least a few thousand barrels per day and one large user like GVEA to be economic.

Kate Lamal, GVEA's vice president of power supply, said her utility is considering converting its North Pole expansion plant from naphtha to propane, but added that their cost estimates are less favorable than those presented by Goldsmith. (Goldsmith's numbers showed savings over naphtha at oil prices above $51 a barrel.)

"We're going to have to make some decision based on our view of what oil is going to be," Lamal said, adding that GVEA is also considering investing in the necessary North Slope infrastructure. Lamal is an ANGDA board member, but has recused herself from any votes dealing with propane.

Several presenters described a chicken-and-egg situation facing the project — consumers are reluctant to convert to propane before an inexpensive supply is available, and suppliers are reluctant to invest in the project until they know the demand is there. A public-private partnership could help the various parties manage risk, according to financial experts speaking at the conference.

Nicholas Hann of Macquarie explained how suppliers could help customers switch to the new fuel by leasing propane appliances.

Competing projects

The propane project is complicated by ongoing efforts to develop a natural gas pipeline. Natural gas delivered in a large-scale pipeline would likely undercut propane from the North Slope in urban areas and would allow new propane plants

see PROPANE page 13

STEFAN MILKOWSKI

ANGDA CEO Harold Heinze wants private industry to take the lead in marketing North Slope propane. Heinze pitched the idea to roughly 100 participants at the Alaska Propane Opportunities Conference in Fairbanks.

The Tanana example

In 2007, the Alaska Natural Gas Development Authority teamed up with the village of Tanana to study the feasibility of using propane in villages along the Yukon and Kuskokwim rivers. Some Tanana residents already used propane for cooking. The village has since converted its teacher-housing unit to propane for heat, hot water, clothes drying and cooking, and is exploring other propane-related technologies.

Ketzler said he's also hoping to test a hybrid propane unit providing household heat, hot water and electricity once the units receive a UL listing in the U.S. He added that he's encouraging the local electric utility to consider using a propane generator.

City Manager Bear Ketzler said propane still costs more than $5 per gallon in the Yukon River village, but added that he was able to reduce the cost to $3.47 a gallon by buying two large, 1,000-gallon tanks and buying the fuel in bulk. If ANGDA's cost estimates prove true, Ketzler told conference-goers, the North Slope propane project could provide significant savings to Tanana and other villages.

In an interview, Ketzler said the biggest challenge so far has been the lack of workers in rural Alaska trained to handle propane. He said he's been working with the Denali Commission and the state Department of Labor and Workforce Development to schedule a weeklong training session this fall for 15 workers from villages across Alaska. Workers will be trained in handling and transferring propane and in installing propane appliances.

Ketzler said he's also hoping to test a hybrid propane unit providing household heat, hot water and electricity once the units receive a UL listing in the U.S. He added that he's encouraging the local electric utility to consider using a propane generator.

—STEFAN MILKOWSKI

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PROPANE

to be built at various points along the route.

But Heinze argues the two projects would complement each other. While GVEA may switch to natural gas when it becomes available, Red Dog may never have access to gas, he said. "Frankly, the biggest user may actually be the remote operations on the North Slope."

The project could also impact two smaller natural gas projects that are more dependent on in-state demand — a "bullet" pipeline from the North Slope and a proposal by Fairbanks Natural Gas to truck gas from the North Slope to Fairbanks as liquefied natural gas.

FNG President Dan Britton said in an interview June 16 that ANGDA's project would create significant challenges for his project relating to the siting of North Slope infrastructure. He argued his project is better because it would encourage the build-out of Fairbanks' gas distribution system in advance of a pipeline and said he is continuing to seek customers and financing.

Government support

Alaska's Congressional delegation and Gov. Sarah Palin offered general endorsements for the idea.

In a video-taped message, U.S. Sen. Lisa Murkowski described propane as "a shovel-ready solution to the energy crisis that's stifling Alaska's rural economy."

Palin, in a letter read by special assistant Joe Balash, said using propane could be "a part of the answer."

Palin did not support a budget request from ANGDA this year and instead directed funds toward the in-state gas line effort directed by Harry Noah. Heinze said ANGDA is trying to stretch a previous appropriation as far as possible.

In an interview, Balash said the governor does support the propane project.

"It's not going to happen unless it provides some competitive advantage pricewise with the current forms of energy," Balash said. "Anything that gets done to reduce the cost of energy in any Alaska community is a good thing."

Balash acknowledged the project could negatively impact an in-state gas line, but added, "we're not going to close off this opportunity just because there might be an opportunity on a bullet line." ●

● EXPLORATION & PRODUCTION

Alberta bitumen production on the way up

Province's energy regulator points to 131% increase over next decade to 3 million bpd; forecasts 36% drop in gas, excluding shale

By GARY PARK
For Petroleum News

Alberta bitumen production will increase by 131 percent over the next decade to 3 million barrels per day, accounting for 88 percent of the province's total oil output, the Energy Resources Conservation Board has predicted.

The regulator's annual report takes a more bullish view of the long-term than the Canadian Association of Petroleum Producers, which estimated in late May that oil sands production could reach 2.2 million bpd in 2015 and 3.3 million bpd in 2025, based on a conservative scenario in which oil prices remain high enough to support developments and the world economy recovers.

Gas production in Alberta is forecast to make a steady, but relentless descent from 4.42 trillion cubic feet in 2008 to 2.8 tcf in 2018, with consumption in the province expected to grow from 33 percent of output last year to 58 percent in 2018 as demand for industrial use builds.

That raises questions about how much will be available for export to the United States, although the ERCB said that knowledge of shale gas potential in Alberta is "still quite limited," with a number of projects at only the pilot stage or the initial point of development.

For now, the ERCB said it will not attempt to estimate what it believes are significant shale gas reserves while it monitors exploration and development activity.

Bitumen reserves 170B barrels

The province's total remaining established bitumen reserves are placed at 170.4 billion barrels and conventional oil at 1.5 billion barrels.

Reserves at the end of 2008 were down marginally from a year earlier because of a reassessment of reserves and production during 2008.

Bitumen yielded an average 1.3 million bpd during the year, a decrease of 1 percent from 2007, reflecting an 8 percent drop in mined output to about 723,000 bpd, although output from in-situ projects rose 9 percent to about 584,000 bpd.

About 59 percent of the bitumen production was upgraded in Alberta, and synthetic crude production totaled almost 655,000 bpd — a number the ERCB expects will grow to 1.54 million bpd by 2018, depending partly on oil prices which the regulator anticipates will rise from an average US$55 per barrel this year to US$120 in 2018.

The province's conventional oil production averaged 502,800 bpd last year, a drop of 3.8 percent from 2007.

Exploratory and development drilling along with enhanced oil recovery schemes contributed 130 million barrels to the reserves, replacing 77 percent of 2008 production.

Oil wells brought on stream in 2008 dropped fractionally to 1,738 last year from 1,745 in 2007 — a number the ERCB anticipates will fall sharply this year to 1,200.

Some positive gas showings

Although facing decline, Alberta's conventional gas fields had some positive showings last year with established marketable reserves growing by 1 percent in 2008 to 37.8 tcf. Reserves added from drilling contributed 3.55 tcf, replacing 81 percent of production, while positive revisions to older reserves totaled 4.18 tcf, partly offset by negative revisions of 2.25 tcf.

The province has 7,907 conventional gas well connections last year, off 15 percent from 2007, and is expected to show a further drop to 6,800 this year.

Remaining established coalbed methane gas reserves were 1 tcf entering 2009, a gain of 141 billion cubic feet.

Coalbed methane production in 2008 averaged almost 600 million cubic feet per day, although hybrid wells contributed about 774 million cubic feet per day of both coalbed methane and conventional gas.

Coalbed methane well connections tallied 1,466 in 2008, compared with 2,465 wells in 2007, and are expected to stay almost flat this year at 1,400. ●

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OCS LITIGATION

and cancel the Alaska lease sales than it would if it were starting on a level playing field," plaintiffs told the court.

State's interests

"Alaska is unique among states in its economic dependence on oil and gas development," the State of Alaska told the court in a memorandum in support of its motion to intervene.

Although proposed OCS leasing and activities would take place in federal waters, staging activities likely would take place in Alaska, the state said, and if those activities were curtailed the state would be "harmed by the loss of property tax revenues, employment and income to local communities."

The state also can benefit indirectly because successful development on federal lands can make development on adjacent state lands more economic because of infrastructure investments made for development on federal lands. "Any potential development of hydrocarbon bearing state lands adjacent or near to Sale 193 leases become increasingly uneconomic should Sale 193 leases be rescinded."

Oil from the Chukchi would be sent to market through the trans-Alaska oil pipeline, the state said, and would increase throughput in that line, lowering the unit cost for all Alaska oil. Because state royalties and taxes are based on the value of oil in Alaska, less the transportation cost, reduction of the unit cost to ship that oil would increase state revenues.

The state said its significant interests "are not adequately protected by other parties," and said it did not attempt to intervene earlier because when the case was initiated the state had confidence its claims would be represented by federal defendants. It told the court it hopes its interests will continue to be aligned with federal interests, but said "in an abundance of caution, the state must act to ensure its interests are protected until such time that the new federal administration's policy positions are fully articulated." ●

Petroleum news

Oil Patch Bits

Tutka's Sommer receives certification

Tutka LLC said June 2 that John Sommer, EIT, construction manager, has received a professional certification in erosion and sediment control from Environment International Inc. and will be performing erosion and sediment control consulting services for Tutka clients.

JOHN SOMMER

Sommer has more than 15 years of experience in the construction industry and earned his bachelor's degree in civil engineering from the University of Alaska Fairbanks. He has participated extensively in infrastructure construction, supply, design and building projects for clients such as general contractors and various federal and local government agencies. He has a reputation for providing clients with construction innovation, cost-benefit analysis and facilitating challenging logistics on remote projects throughout the state of Alaska.

Tutka has been providing its clients with construction, environmental, instrumentation and government services since 1999. With offices in Anchorage, Fairbanks and Wasilla, it continues to grow and offer more technical services to its already established customer base.

Schlumberger awards scholarships

Schlumberger said June 9 that it has contributed two scholarships to the American Association of Petroleum Geologists Outstanding Student Chapter Awards. Among the United States-based chapters, Southern Methodist University in Dallas, Texas, received an award and was honored as outstanding international chapter, as was the University of Bucharest in Bucharest, Romania.

"Schlumberger is committed to working with universities that continue to enhance their petroleum geosciences curriculum," said Terry Woods, operations manager, Schlumberger Data and Consulting Services, Rockies and California. "We are honored to be able to support AAPG with its student's development programs as these university students and future geoscientists will one day be our leaders in the oil and gas industry."

Awards are presented yearly at the AAPG annual meeting. Student chapter requirements for selection of awards include maintenance of student AAPG memberships, active AAPG faculty sponsor, and participation in earth science week, field trips, meetings and special community events. This is the 12th year Schlumberger has sponsored the scholarships.

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

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

Oil Patch Bits

Nabors announces realignment

Nabors Industries Ltd. said June 11 that Larry P. Heidt will assume the role of chairman and CEO of Nabors Well Services Ltd. Heidt has been with Nabors more than 17 years, initially serving as president of Nabors' U.S. Lower 48 land drilling operations, Nabors Drilling USA LP. Since 2004 he has served as special assistant to the chairman, working on numerous strategic projects for the corporation.

Nick Petronio, president of Nabors Well Services Ltd., will continue to be responsible for all operations and operational support services, as well as the marketing function, and will report directly to Heidt. In addition, Dan Ehlert, vice president of finance and administration, Frank Labrenz, vice president of personnel services, and Lauri McDonald, director of credit, all will report directly to Heidt.

The Nabors companies own and operate approximately 534 land drilling rigs and approximately 763 land workover and well-servicing rigs in North America.

Perkins Coie named among top in Chambers USA

Perkins Coie said June 1 that once again it has been ranked by Chambers & Partners, publishers of Chambers USA: America's Leading Lawyers for Business, as a top law firm in the United States. Perkins Coie was recognized in the annual directory as a leader, having obtained Band 1 placement in 14 practice areas with top rankings in eight key markets across the country, including Alaska, Arizona, California, Colorado, Idaho, Illinois, Oregon and Washington. The rankings are the result of extensive surveys and interviews of in-house counsel and leading law firm partners.

"It is an honor to be recognized for excellence in so many practice areas," said Robert E. Giles, managing partner. "Our clients drive our success and we thank them for bringing us challenging and interesting work. This recognition is a reflection of the great companies we counsel."

With more than 700 lawyers in 15 offices across the United States and in China, Perkins Coie serves great companies ranging in size from startups to Fortune 100.

Crowley tug contract extended in Washington

COURTESY CROWLEY

Crowley Maritime Corp. said June 16 that the Washington Department of Ecology has extended its contract agreement with Crowley to station a state-funded emergency response tug at Neah Bay for another full year of service beginning July 1, 2009, through June 30, 2010.

Under the $3.6 million extension agreement, an emergency response tug will remain at Neah Bay to prevent disabled ships and barges from drifting onto rocks and causing oil spills in the Strait of Juan de Fuca and Washington's outer coast. The contract marks the final year the state will pay for the emergency response tug service. On March 24, 2009, Gov. Chris Gregoire signed legislation that shifted funding responsibility for the Neah Bay tug from the state to the maritime industry beginning July 1, 2010. The new law will ensure a high-capability ocean-going tug is permanently deployed at Neah Bay year round.

Alliance posts result of annual golf tournament

COURTESY THE ALLIANCE

The Alliance said June 15 that it has posted the results of its annual Alliance Golf Tournament at Moose Run and the Calcutta that took place the evening prior at the Petroleum Club.

The event is the fourth largest fundraising events for the Alliance and plays an important role in keeping the organization strong, as well as providing a great networking opportunity for those businesses that participate. For more information and posted results visit www.alaskaalliance.com.

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● FINANCE & ECONOMY

Appeals court orders Exxon to pay interest

By MARK THIESSEN

Associated Press Writer

Exxon Mobil Corp. was ordered June 15 to pay about $500 million in interest on punitive damages for the Exxon Valdez oil spill off Alaska, nearly doubling the payout to Alaska Natives, fishermen, business owners and others harmed by the 1989 disaster.

The ruling was issued by the 9th U.S. Circuit Court of Appeals in San Francisco.

In June 2008, the U.S. Supreme Court set punitive damages at $507.5 million. But two months later, the high court declined to decide whether Exxon Mobil must pay interest on the punitive damages awarded in the nation's worst oil spill and instead sent it back to the appeals court.

The June 15 decision would double the average payout of about $15,000 for the nearly 33,000 claimants.

"We're just happy that we've cleared another hurdle, and hopefully we can get the case tied up as soon as possible," Stanford University law professor Jeffrey Fisher, an attorney for the plaintiffs, told The Associated Press June 15. "What we want more than anything now is just to bring this case to a close."

Exxon could appeal the decision on the interest payments to the Supreme Court. A spokesman for Exxon told the AP in an e-mail that the company would comment after the decision has been reviewed.

The case grew out of the 1989 crash of the Exxon Valdez, a supertanker that dumped 11 million gallons of crude oil into Alaska's Prince William Sound, fouling 1,200 miles of coastline.

Plaintiffs originally were awarded $5 billion, but that amount was cut in subsequent appeals by Irving, Texas-based Exxon.

A jury decided in 1994 that Exxon should pay $5 billion in punitive damages. In 2006, a federal appeals court cut that verdict in half.

The Supreme Court last June slashed the $2.5 billion punitive damages award to $507.5 million.

Exxon had contended that if interest were paid, it should be calculated from the date the punitive damages were set last year by the Supreme Court. But in the June 15 ruling, the court said interest on the $507.5 million judgment should run from 1996, when the original settlement was entered into court records, at a rate of 5.9 percent.

The spill killed hundreds of thousands of birds and other marine animals, inflicting environmental damage from which the region has not fully recovered, according to numerous scientific studies.

ExxonMobil countered that many studies have found the area healthy and thriving. The company had argued punitive damages would be excessive punishment on top of the $3.4 billion in cleanup costs, compensatory payments and fines it already has paid.

Exxon maintained it should not be liable for the actions of the supertanker's skipper, Joseph Hazelwood, when the nearly 1,000-foot vessel ran aground with 53 million gallons of oil in its hold.

According to prosecutors, Hazelwood was drunk, but he denied it and was acquitted of the charge in criminal court. ●

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OPPOSITION

leases within the proposed unit."

Such an unwieldy situation with the multiple operating agreements could result in waste of unit resources, and unfairly favor the interests of some partners over others.

TG World's third objection concerns access to certain documentation backing up the unit application. The company says AVCG and Brooks Range have withheld critical information including a two-volume "Geological, Geophysical and Engineering Submittal" for which TG World had paid its share.

In its comments to the state, TG World says it has paid a 35 percent share of pre-development costs for the Beechey Point unit, or $687,190 between 2007 and 2008.

The company said it "supports the efficient, fair and equitable formation" of the unit, but asks that the state natural resources commissioner "hold the application in abeyance" until the problems are fixed.

With its filing, TG World supplied the state a June 4 letter signed by James Winegarner, vice president of land and external affairs for Brooks Range, partially addressing some of TG World's complaints.

The letter says the 12 leases in which TG World claims part interest "will not be assigned to TG" until the court litigation is resolved. ●

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DEMAND

sumers efficiently and without interruption," he added.

Despite "dramatic gyrations in the world economy and energy prices" in 2008, the annual Review reported that the markets served energy security well during the year, according to BP Chief Economist Christof Ruehl.

"Allowing markets to continue to function freely and without interference remains key to managing the inevitable ups and downs in prices as we go forward," Ruehl said.

Prices peak; demand plummets

In 2008 the average price of dated Brent crude oil rose to $97.26 a barrel — 34 percent up on the previous year and the seventh consecutive annual rise. However, the annual average masked huge variations during the year, according to the Review.

Oil prices began 2008 at just below $100 a barrel, peaked above $140 in early July and fell dramatically to less than $40 at year's end — the fall a consequence of higher OPEC production and rapid slowdowns in consumption in the second half.

Over the year, global oil consumption fell by six-tenths of 1 percent, or 420,000 barrels per day; the first decline since 1993 and the largest drop in 27 years. This included a steep fall in demand of 1.5 million bpd from the 30 Organization for Economic Cooperation and Development countries, which includes the European Union and the United States, and slower growth in demand (up just 1.1 million bpd) among developing nations. This was OECD's third consecutive year of decline.

OPEC drives slightly higher output

Despite overall lower demand, average oil production rose four-tenths of 1 percent, or 380,000 bpd, driven largely by OPEC production increases. Despite cuts late in the year, average OPEC oil output actually rose by almost 1 million bpd, or 2.7 percent.

The Middle East saw the entire boost in daily production, with Saudi Arabia's output climbing by 400,000 bpd and Iraq's up 280,000 bpd, the Review reported.

Outside OPEC, crude production recorded the steepest decline since 1992, falling by 1.4 percent, or 601,000 bpd, with output from OECD countries falling 4 percent, or 750,000 bpd, driven by declines in North America and Europe. The single largest decline came from Mexico, where production decreased 310,000 bpd. Russian production also fell for the first time since 1998, by 90,000 bpd, while United Kingdom oil output fell 94,000 bpd, the lowest level for 30 years.

The world's remaining proved oil reserves, excluding Canadian oil sands, totalled 1,258 billion barrels — enough for 42 years at 2008 production rates, according to the Review. On the same basis, reserves of natural gas are sufficient for 60 years and coal for 122 years.

World appetite for gas grows

Gas consumption grew by 2.5 percent in 2008, but still languished below the 10-year average, according to the Review. U.S. consumption rose by six-tenths of 1 percent as spot prices remained well below oil prices. The largest incremental growth in world gas demand was from China, where consumption rose 15.8 percent. The U.K.'s gas consumption grew by 3 percent, with gas now supplying 39.9 percent of the U.K.'s total primary energy — well above the global average of 24.1 percent. Elsewhere, only the Middle East saw above-average growth, driven by strong domestic demand.

Oil-indexed gas prices in OECD Europe and Asia-Pacific rose more rapidly which, coupled with the recessionary impact, meant that consumption growth was below average.

Globally, gas production rose 3.8 percent, above the 10-year trend of 3 percent. This was driven strongly by U.S. gas output, which recorded its highest-ever annual increase as strong activity in development of unconventional gas resources boosted production by 7.5 percent, or 10 times the 10-year average growth rate. The second highest increase came from Qatar as pipeline exports of gas to the United Arab Emirates increased. Production also rose in Europe overall as increases in Denmark, Netherlands and Norway gas output more than offset declines in the U.K. and Germany.

Robust renewables growth

Renewable energy again grew strongly albeit from a low base, with wind and solar generating capacity growing 29.9 percent and 69 percent, respectively, both above their 10-year average rate, according to the Review.

Wind power generating capacity in the United States grew by 49.5 percent, overtaking Germany to become the nation with the world's largest installed wind generating capacity. U.K. wind-generating capacity grew 36.3 percent to 3.3 gigawatts, which accounts for less than 3 percent of installed capacity worldwide.

Hydroelectric production continued its recent strong performance with growth of 2.8 percent, above the 10-year average for the fourth time in the past five years. However, all of the global increase could be accounted for by growth in China — climbing by 20.3 percent, nearly twice the country's 10-year average rate. Hydroelectric generation outside China fell by four-tenths of 1 percent.

Nuclear output fell for the second consecutive year, by seven-tenths of 1 percent, led by a 10 percent decline in Japanese output as its largest power station remained shut after a 2007 earthquake.

Coal demand strong in China

For the sixth consecutive year, coal remained the fastest growing fuel globally, even though its 3.1 percent growth in consumption fell below the 10-year trend. China, which accounts for fully 43 percent of global demand for coal, accounted for 85 percent of this growth, with an increase of 6.8 percent.

Outside China, growth in demand for coal globally was weak, climbing only 0.6 percent and reflecting the fact that coal prices in liberalized markets increased more than for any other fossil fuel. Coal use in the U.K. fell 7.6 percent to the lowest level in a decade, in part due to fuel switching driven by carbon dioxide prices in the European Union's emission trading scheme.

Energy consumption slows

Overall primary energy consumption nudged up just 1.4 percent, the smallest rise since 2001 and largely due to the extremes of the world economy in 2008 — strong growth followed by sharp decline, the Review reported. China alone accounted for almost three quarters of the rise, with most of the balance coming from the wider Asia-Pacific region.

In the OECD nations, energy consumption fell by 1.3 percent, with demand in the United States seeing the steepest single-year decline since 1982, a drop of 2.8 percent. ●

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INVESTING

field services company Aker Solutions, said that while "local resources" are available in Arctic regions, finding and maintaining qualified personnel is a major challenge for his company, as well as health and safety issues.

"In these remote areas, putting 6,000 to 7,000 people in camp locations presents challenges for family issues, substance abuse, disease; and you have to manage all that; you have to plan for it, with clinics and hospitals," Mandel told OTC. "With the rotation of the people in and out, due to these extreme conditions, many don't come back. So you have to plan for the high turnover during execution of the projects. With these remote locations, long tiebacks and long distance to market is another issue that brings complexity to these developments."

And that's not all. As part of its planning, Aker attempts to "minimize the manpower" on site and does as much facility prefabrication and modular work as possible. Additionally, facilities have to be designed to house workers during the construction phase and for operators during the production phase.

"Obviously there are constraints to the amount of prefabrication and modularization you can do off site," Mandel said. "Some areas are only accessible by rivers in certain periods of the year. Additionally, winterization of facilities is to an extreme. You almost have to keep track of almost everything you do there, to be able to construct as well as operate."

Knowing the ice

Moreover, if a company plans to operate in the Arctic, ice management is critical, Mandel said, noting that since 1967, Aker has maintained an "ice laboratory" in Finland. Consequently, Aker has accumulated one of the largest and most extensive ice-management data bases in the world.

"We're constantly doing research and feeding that database," Mandel said, adding that there has been a "huge collaborative effort" at sharing information. "And that's why you see that multiple owners and operators have benefitted from that ice laboratory. We share that data for the benefit of industry."

Aker companies, which have executed projects in harsh environments globally from Sakhalin to Newfoundland, also have designed more than 60 percent of the world's icebreaking vessels, as well as some of the most advanced cold and harsh climate drilling rigs.

"So there is a lot of experience and lessons learned … that gets into each generation of design," Mandel said. "One of the things that our experience tells us is that you have to thoroughly test all Arctic concepts and solutions, to see how they behave in ice before implementing them, and we do that in the ice laboratory."

Mandel noted that in addition to dealing with the long winter months, including ice conditions, extreme temperatures and extreme winds associated with cold temperatures, the typically short summer months present their own unique challenges.

"There are myriads of mosquitoes and problems associated with remote locations," he said. "There're very limited weather windows to bring in equipment and materials — the logistics, etc."

Arctic work not new

ConocoPhillips, largely through its position on Alaska's North Slope, is among the globe's largest and most experienced Arctic producers, with a proportionally large chunk of annual capital expenditures going to cold climates, including the North Slope, as well as to its partnership with Russia's Lukoil and to sub-Arctic operations in Sakhalin Island.

"Working in the Arctic is not new," ConocoPhillips' Noble told OTC. "The Arctic has been seen as a potential for all kinds of resources for a long time," including fishing, whaling and mining. "So there is a lot of experience in doing large-scale resource extraction projects in cold regions far from logistics. We're not starting from square one. We do have a long history of doing that."

Noble suggested that because much of the Arctic lies offshore in relatively shallow waters of 300 feet or less, remote oil and gas developments in countries bordering on the Arctic Circle could be challenged by a lack of ice-free, deepwater ports necessary to harbor product tankers. Though there are "ice-free zones" in areas of the Barents Sea and western Greenland, for example, "by and large we're talking about a shallow sea," he added.

On a positive note, Noble indicated that news stories playing up potential jurisdictional disputes over areas of the Arctic that currently lie in international territory are misleading. In a highly publicized stunt, for example, Russia laid claim to a remote area of the Arctic by planting a flag beneath the polar cap using an unmanned submersible.

"I don't see this kind of thing as being a big hurdle. … The places where oil and gas companies want to go are clearly within one jurisdiction or another," Noble explained.

Technology has improved

Noble agrees with Aker's Mandel that ice management is a critical factor when it comes to planning offshore Arctic oil and gas projects. For one, ice detection technology has improved significantly since the last major push into offshore Arctic during the late 1970s and early 1980s, when there was a flurry of exploration activity in the Canadian Beaufort Sea, some of which resulted in significant natural gas discoveries that would anchor a proposed gas pipeline from Canada to the U.S. Lower 48.

"We have better information on where the ice is, how thick it is, and what it's doing," Noble said, explaining that in addition to traditional ice charts, SAR (synthetic aperture radar), largely formed from satellite imagery, is among several new tools available to industry. "It allows you to make pictures whether it is dark or cloudy … which can determine ice conditions and that is a big plus."

Moreover, rather than send manned fixed-wing aircraft and helicopters into potentially dangerous weather conditions, unmanned drones equipped with the latest imagery technology can be dispatched to verify satellite data.

"So there are a lot of tools available to us today that are being used and can be further adapted to work," Noble said. "But we need to improve ice forecasting, ice information."

Because each offshore project must be tailored to fit specific ice and weather conditions, designing and building exploration rigs and production facilities for offshore Arctic remains a major industry challenge. For example, some rigs work well in light, early winter ice conditions but are unsuccessful when it comes to open waters with limited drilling seasons.

"Arctic Ocean drilling systems solutions are quite important … so getting the balance in design and development of these systems is important," Noble said. "We have very limited seasons, sometimes in the tens of days. So that extends the whole exploration (process), and certainly when it comes to development drilling, it extends that too. We need to get better solutions for that."

Transportation an issue

Seasonable shipping from remote Arctic regions is possible although probably not doable for natural gas, Noble said, adding that produced oil could be stored but that option may damage reservoirs, if they are shut down when storage is full and then restarted when ocean shipping resumes.

"We need to develop year around shipping," he said. "Pipelines, even though I'm a naval architect and certainly favor marine solutions, even in the pipeline world there is a lot of marine work in how you trench pipelines, how to lay them in the Arctic. And it will be a combination of developments, I think."

Noble concluded:

"You really have to be self-sufficient (in the Arctic). It may be that we have to look at different ways of doing things. But no one company, whether it is an oil major or a contractor can do this alone. And it's important that we work together on this … and understand what it is we need to do, do it, and then let the rest of the world know that we can be safe and have sustainable development in the Arctic." ●

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TANKER

dominantly single-hulled ships to double hulls.

Two of the major North Slope oil producers, BP and ConocoPhillips, built brand-new fleets of double-hulled tankers. Exxon, however, hasn't built new ships, choosing instead to use or acquire older double hulls that carry no mandatory retirement date under OPA 90.

Afterlife for old tankers

The overall number of tankers has been declining in recent years as North Slope oil production declines. Production peaked at more than 2.1 million barrels per day in early 1988, but was averaging 635,000 barrels per day through mid-June of this year.

The Long Beach is a sister ship of the single-hulled Exxon Valdez, which Congress banished from Alaska waters following the spill.

SeaRiver's spokesman, Botto, emphasized the Long Beach "is still fully certified to operate" as an oil tanker. He cited security concerns, including the threat of piracy, in declining to say where the ship is located now, or where it's headed.

He said options for the Long Beach could include converting it to a double-hulled tanker or retrofitting it for some other use. But saying more about plans for the ship, Botto said, would be "speculative or proprietary."

The Washington Ecology Department list says no double-hull conversion is planned for the Long Beach.

According to the shipping Web site vesseltracker.com, the Exxon Valdez is now called the Dong Fang Ocean. The ship belongs to Hong Kong Bloom Shipping and operates as an ore carrier under the flag of Panama.

—WESLEY LOY

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WHO?

Enbridge told a conference the industry is overbuilt, pointing to weak prices for a long time.

He said it is unlikely that Arctic gas, from either Alaska or the Mackenzie Delta will be needed before 2025.

Letwin said the cost of building transportation facilities could run to about US$5 per million British thermal units for the Alaska line.

Eresman: markets oversupplied

A strong indication of the current state of the North American gas market came from EnCana June 15 when the big producer said it had entered fixed price hedge contracts for 35 percent of its expected production in the upcoming sales year from Nov. 1, 2009, to Oct. 31, 2010.

EnCana said it will get an average US$6.21 per thousand cubic feet for 1.39 billion cubic feet per day, compared with its current hedged price of US$9.13 for about two-thirds of its 2008-09 production, or 2.6 billion cubic feet per day.

EnCana Chief Executive Officer Randy Eresman said the present hedging program generated close to US$2 billion in cash flow above what market prices would have delivered in the first five months of 2009.

But he said North American markets "remain oversupplied, due to two factors — the emergence of large new supplies from unconventional plays, followed by a major economic downturn in the past year that has cut demand."

Eresman said these events have pushed prices below what it costs to add new supplies, although his company believes those levels are "unsustainable."

"In recent months, drilling has slowed and over time we expect that production will decline, bringing the market back into balance. However, it is difficult to predict when that will occur and what price will emerge," he said.

Looking long-term

But proponents of Arctic gas ventures have held fast to the line over recent years that their projects are proceeding on their estimate of where gas supplies and prices are headed over the long-term.

Imperial Oil (69.6 percent owned by ExxonMobil and the lead partner in the MGP consortium) reacted to the TransCanada-ExxonMobil partnership announcement with a familiar corporate line that the North American gas market will ultimately need gas from the Arctic regions of both Canada and the United States.

But the company would not be drawn into speculating on the timing of either project, or what the gathering pace of the Alaska project might mean for the MGP.

What Imperial remains focused on is wrapping up the regulatory phase, negotiating commercial and fiscal terms with the Canadian government and concluding access and benefits agreements with communities along the pipeline route in the Northwest Territories.

NWT Industry Minister Bob McLeod said the tilt towards Alaska shows even more the urgent need to settle on fiscal arrangements and conclude the regulatory process.

Otherwise, he found some comfort in assurances by the proponents that both pipelines are needed and — despite some corporate overlap — are independent of each other.

Jim Prentice, the Canadian cabinet minister overseeing the government's role in the MGP, said he has been assured by the chief executive officers of TransCanada (Hal Kvisle) and Imperial (Bruce March) they are still committed to the MGP.

He also suggested the MGP remains several years ahead of Alaska in the planning and regulatory phases and, as he has previously said, it's important the MGP proceed first to avoid competition for construction labor and materials.

Others were not quite so sanguine.

Lack of government support?

Fred Carmichael, chairman of the Aboriginal Pipeline Group, which has rights to acquire a one-third equity stake in the MGP, said it is obvious that ExxonMobil prefers Alaska over Canada because of the potential returns.

He told the Globe and Mail that "as mad as I am, as disappointed as I am, I have to face the reality that this is a business deal and there's more money for (ExxonMobil) and TransCanada to be made on the Alaska pipeline" than on the MGP.

With the MGP "stuck in the mud" he said Alaska is not just moving forward; "it's getting momentum."

Carmichael suggested that if the Canadian government played its part in supporting the MGP, the NWT could reduce its dependence on federal money, which covers almost the entire budget of the territorial government.

Chris Theal, an analyst with Tristone Capital, said ExxonMobil, without saying so openly, has "firmly thrown its weight behind Alaska," while the Canadian government has yet to deliver on its promise this year to deliver a fiscal package for the MGP.

Steven Paget, an analyst with FirstEnergy Capital, told the Calgary Herald that "Alaska just keeps looking better and better all the time."

Steve Letwin, executive vice president for gas transportation at Enbridge, doubts Arctic gas will be needed over the next 15 years because of the prospect for massive development of shale gas.

"Alaska has 36 trillion cubic feet of gas, way up in the North; Haynesville (the shale play in Texas and Louisiana) has potential 70 tcf (close to market), so where are you going to go?" he said.

Bill could boost guarantees

Separately, the NWT government is uneasy that a bill before the U.S. Congress could boost loan guarantees for an Alaska pipeline to $30 billion from the $18 billion set in 2004, with Washington covering 80 percent of total project costs if the pipeline owners defaulted on the financing.

McLeod is pressuring Prentice for answers on whether the playing field has been altered with regard to the loan guarantees.

On the shale gas issue, Letwin said the years of worries over the shrinking conventional gas supplies have given way to concerns that there are not enough buyers for 1,200 trillion cubic feet of shale gas that has been discovered in the past three years, plus imported liquefied natural gas that "is needed like a hole in the head."

As a result, he said gas prices will remain locked in the US$5-$7 range (almost double current trading levels on the New York Mercantile Exchange), for a "long time to come."

While shale producers can operate profitably at low commodity prices, the prevailing market does not give hope to those planning Arctic pipelines.

However, he said the MGP has an edge over the Alaska project because its gas will be needed to fuel extraction and processing of bitumen in the Alberta oil sands, which are much closer to the Arctic source than markets in the Lower 48. ●

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PLAYERS

Taglu field, discovered in 1971.

Shell Canada is outright owner of the Niglintgak field, discovered in 1973, with marketable reserves estimated at 970 billion cubic feet.

ConocoPhillips Canada, with 75 percent, and ExxonMobil Canada, with 25 percent, jointly own the Parsons Lake discovery of 1972, with estimated marketable reserves of 1.8 tcf.

Sharing a spot among the co-venturers is the Aboriginal Pipeline Group, which could represent six aboriginal regions along the pipeline right of way, and holds an option to take up to a one-third equity stake if it is able to deliver incremental gas volumes from independent explorers in the Mackenzie Delta.

Up to 1.2 bcf a day

Current plans before regulators point to combined initial volumes of 830 million to 1.2 billion cubic feet per day, with design capacity for 1.9 bcf per day.

TransCanada is the front-runner to build and operate the main gas line from the Delta to northern Alberta (Enbridge is viewed as a contender to build and operate a natural gas liquids pipeline to its existing crude oil line from Norman Wells to northern Alberta).

TransCanada has contributed upwards of C$85 million to help the APG play its role in the regulatory process.

If the pipeline proceeds, the APG is committed to repaying that loan, while TransCanada has an option to obtain up to 5 percent of the pipeline if the anchor producers choose to reduce their overall share.

If any of the producers sells or reduces its ownership interest in the pipeline, TransCanada has first right to acquire 50 percent of such opportunities, with the APG and other owners sharing the remaining 50 percent.

The full details of various other options available to the APG, TransCanada and the owners are available on the MGP Web site at www.mackenziegasproject.com.

—GARY PARK