Petroleum news

page 4 Commissioner: revenue stream OK but ‘fragile’; strong oil prices needed

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New pumps at work

ALYESKA PIPELINE SERVICE CO.

Pump station 3, in the foothills of the Brooks Range, was the second pump station to begin using new electrical pumping equipment and control systems. See story page 9.

Swanson River gas satellites a go; Chevron, Marathon moving ahead

Both Chevron and Marathon are moving ahead on work at Swanson River satellites where they hope to find commercial quantities of natural gas.

This is an area where gas has been known since the 1960s, with a well drilled in 1965 at the north satellite, Birch Hill, and in 1970 at the east satellite, Sunrise.

The North Swanson River satellite — the existing Birch Hill unit northeast of Swanson River, operated by Chevron subsidiary Unocal — has existed since the 1960s.

An environmental impact statement approving roads to the satellites and expanded and new pad development was finalized in 2004 for the North Swanson River and East Swanson River satellites, both in the Kenai National Wildlife Refuge. A record of decision signed by officials of refuge manager U.S. Fish and Wildlife Service in 2004 and 2005 granted rights of way to Union Oil Company of California and Marathon Oil Co. for development of the Swanson River satellites natural gas exploration and development project.

The North Swanson River satellite — the existing Birch Hill unit northeast of Swanson River, operated by Chevron subsidiary Unocal — has existed since the 1960s. A single well, drilled in 1965, produced 65 million cubic feet of gas over a 12-day test period according to Alaska Oil and Gas Conservation Records. That well is suspended.

In the area of the proposed eastern satellite, on acreage leased by Marathon from Cook Inlet Region Inc., a well was drilled by Forest Oil in 1970 and plugged and abandoned. AOGCC records show that the well, Sunrise Lake Unit 1, had gas shows in the Tyonek formation below 11,000 feet.

Unocal originally applied

Fish and Wildlife said the 2001 application for roads and pads was from Unocal, which would have been the operator at both the

see **SATELLITES** *page 19*

BREAKING NEWS

6 LB&A looking for tax help: Legislature has RFP out for economic analysis and modeling for Alaska natural gas taxation

8 Kitimat lines up first gas: LNG project signs with EOG Resources, which has major stake in B.C.’s Horn River shale

15 PWS RCAC seeks new head: John Devens, former executive director of Valdez-based watchdog group, resigned in May

PIPELINES & DOWNSTREAM

Drift River restart

CIPL to restart oil terminal, bypassing the tank farm to offload inlet oil

By ALAN BAILEY
Petroleum News

Following three months of speculation about the future of the Cook Inlet oil industry after the April 4 shut-in of most western Cook Inlet oil fields, after an explosion at the erupting Redoubt Volcano had sent a second flood of mud-laden water around the beleaguered Drift River Oil Terminal on the volcano’s flanks, Cook Inlet Pipe Line Co. announced July 13 that, with the volcano quieting down, the company hopes to start shipping oil from Drift River again, starting mid-August.

CIPL plans to pump oil delivered from the Cook Inlet pipeline directly into tankers moored at the terminal’s Cindy Lee platform, without using the terminal storage tanks but instead depending on oil storage in tanks located in Chevron oil production facilities at Granite Point and Trading Bay. The CIPL-operated Cook Inlet pipeline connects Granite Point and Trading Bay to Drift River, with

CIPL spokesman Santana Gonzalez told Petroleum News July 17 that CIPL is replacing pumps and metering systems at the terminal, as a result of which it will be possible to increase oil flow rates, to enable efficient transfer of oil direct to the tankers.

see **DRIFT RIVER** *page 20*

FINANCE & ECONOMY

Canadian S&S in trouble

CAODC drops well completion forecast by 29%; rig utilization forecast at 25.5%

By GARY PARK
For Petroleum News

Canada’s upstream service sector is no longer mincing words about the outlook for the rest of 2009.

Don Herring, president of the Canadian Association of Oilwell Drilling Contractors, said the industry has found itself in “dire straits” and has now served notice to its members and others that the industry is in “real trouble.”

His grim message came as CAODC issued a second revision to its well-completion forecast, calling for 8,787 wells to be drilled, down 29 percent from its February adjustment and 39 percent below what it originally projected last October.

If that target is achieved, CAODC said an average 25.5 percent or 219 from an available fleet of 815 rigs will be kept busy through 2009, 60 percent below the record drilling years of 2005 and 2006 when 21,999 and 22,127 wells were completed. In 2006, rig utilization was 63 percent of 795 rigs.

For the opening quarter of 2009, utilization was 37 percent, or 320 rigs, dropping sharply to 11 percent or 92 rigs in the second quarter. The projection for the current quarter is a utilization rate of 25 percent, edg-

New well permits issued by regulators slumped to 1,769 in the second quarter, down from 3,689 in the same period of 2008, while the first half count was 5,285 wells compared with 8,725 to the midpoint of 2008.

see **OUTLOOK** *page 19*

GOVERNMENT

State defends BP suit

Company trying to ‘delay, complicate’ Prudhoe spill case, state lawyers say

By WESLEY LOY
For Petroleum News

Lawyers for the state are opposing BP’s efforts to toss out part of a lawsuit seeking potentially huge damages stemming from Prudhoe Bay oil spills in 2006.

They argue attorneys for BP Exploration (Alaska) Inc. are trying to belittle the magnitude of the events of three years ago, and to “delay and complicate this lawsuit” by asking a judge to kick part of the case to the Alaska Oil and Gas Conservation Commission.

“BPXA tries to characterize this lawsuit as one involving only two relatively minor oil spills (despite the fact that the March 2006 spill was the largest ever on the North Slope), which it cleaned up right away (ignoring the fact that it had a clear legal obligation to do so),” the state’s lawyers wrote in a July 10 filing in Anchorage Superior Court. “Moreover, the March 2006 spill prompted immediate pipeline integrity inspection orders and

A written summary of a recent conference before Judge Michalski says lawyers agree the trial “probably won’t be ready in a year.” The summary indicates the two sides have “attempted some form of settlement already.”

see **LAWSUIT** *page 18*

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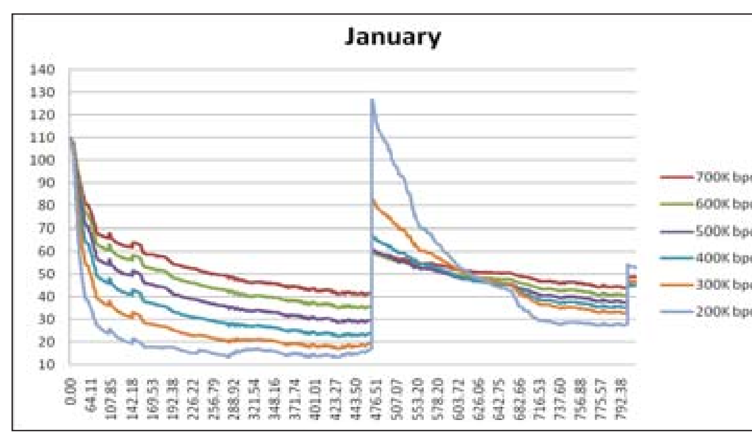

Alaska - Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay DS18-31	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked at Deadhorse	Available
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay DS 01-30	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD2-73	ConocoPhillips
OIME 2000	141 (SCR/TD)	Stacked at Deadhorse	Available
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 1C-11	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay, Stacked out	BP
Mid-Continental U36A	3-S	Stacked, Milne Point	BP
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay WGI-07	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay Maintenance	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 7-28b	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site B-14	BP
Ideco 900	3 (SCR/TD)	Stacked out, Kuparuk	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

Interior

Doyon Drilling			
TSM 7000	Arctic Wolf #2	Rigging up at Nunivak#1 near Nenana	Rampart Energy

Cook Inlet Basin – Onshore

Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	planned August 3 move date for Kaloa 2 workover	Aurora Gas
Kuukpik	5	Stacked in Kenai	Available
Doyon Drilling			
TSM 7000	Arctic Fox #1	Mobilizing at Beluga	ConocoPhillips
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	M-18 Steelhead platform	Chevron
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO

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 July 16, 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*

	July 10	July 2	Year Ago
US	916	928	1,922
Canada	178	165	414
Gulf	37	42	67

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

● FINANCE & ECONOMY

State revenue stream OK but ‘fragile’

Assuming strong oil prices, state will have plenty of cash for budgeting and can build its savings, revenue commissioner says

Explorers trade tax credits for cash

The State of Alaska paid $193 million in cash over the past year to oil and gas explorers in exchange for tax credits they had accrued for making investments in the state, the Alaska Department of Revenue announced July 10.

The payments are designed to give explorers an incentive to hunt and develop oil and gas deposits in Alaska.

For fiscal year 2009, which ended on June 30, the state distributed the $193 million to 15 “new” oil and gas explorers, the department said.

By new, the state means companies that might be familiar names in Alaska but aren’t yet producing any oil or gas, said state Revenue Commissioner Pat Galvin. He said he couldn’t by law reveal the names of the firms as individual taxpayers.

Galvin said fiscal year 2009 is the first full year the state has reimbursed companies for their credits under ACES — Alaska’s Clear and Equitable Share, the oil production tax reform Gov. Sarah Palin pushed through the Legislature in late 2007.

The credits are essentially advance rebates on future taxes the companies will owe once they begin production. Companies present proof of their spending to the

see **EXPLORERS** *page 17*

By WESLEY LOY
For Petroleum News

Prospects are decent for ample revenue to support state government and preserve savings through the year 2020, but Alaska’s finances will remain “fragile” due to heavy dependence on oil production, state Revenue Commissioner Pat Galvin says.


PAT GALVIN

Revenue from oil production taxes, royalties, corporate income tax and property tax combine for about 88 percent of the state’s general, unrestricted revenue. The production tax alone accounts for 50 percent.

The big variable is the price of oil, which is “more volatile than ever,” Galvin said at a luncheon the public policy forum Commonwealth North sponsored July 9 in Anchorage. Former governors Wally Hickel and the late Bill Egan co-founded the group.

State officials expend a lot of energy trying to forecast oil prices. Based on their latest projection, coupled with the level of oil production, state general revenue could grow from $5.9 billion in fiscal year 2009, which ended on the last day of June, to $7.6 billion in fiscal year 2020, Galvin said.

Further, one of the state’s main savings accounts, the Constitutional Budget Reserve, has potential to grow from $6.6 billion to $23 billion, assuming legislators sock away rather than spend surpluses.

Relatively rich, but …

The future sounds pretty rosy, especially considering the far more austere outlook only two years ago — before the big spike in oil prices — and the dire budget crunches other states are facing.

“We’re stable. We can sustain the current level of spending, given our current expectation of revenue,” Galvin said in a July 15 interview with Petroleum News.

But Galvin cautions that Alaska’s revenue outlook hinges not only on oil prices, but on the assumption of “a very modest spending expectation going forward.”

The outlook doesn’t factor in large capital budgets for construction and other projects, and is based on annual spending growth of 3 percent, Galvin said.

If Alaska wants to expand its economy and make big investments such as tackling deferred maintenance on state buildings, constructing roads or laying the groundwork for a natural gas pipeline, it might have to look “beyond the current system” for the money, he said.

Lower than expected oil prices could wipe out Alaska’s savings well before 2020, even assuming no growth in budget appropriations, Galvin added.

Oil production outlook

Galvin showed the Commonwealth North audience a graph plotting Alaska’s historic and projected oil production, and again the picture looks not so bad. The graph shows that in 2000, oil production exceeded 1 million barrels per day. For this year through 2020, the production level stays essentially flat at just over

see **REVENUE** *page 17*

Alaska state government overwhelmingly dependent on oil production taxes, royalties

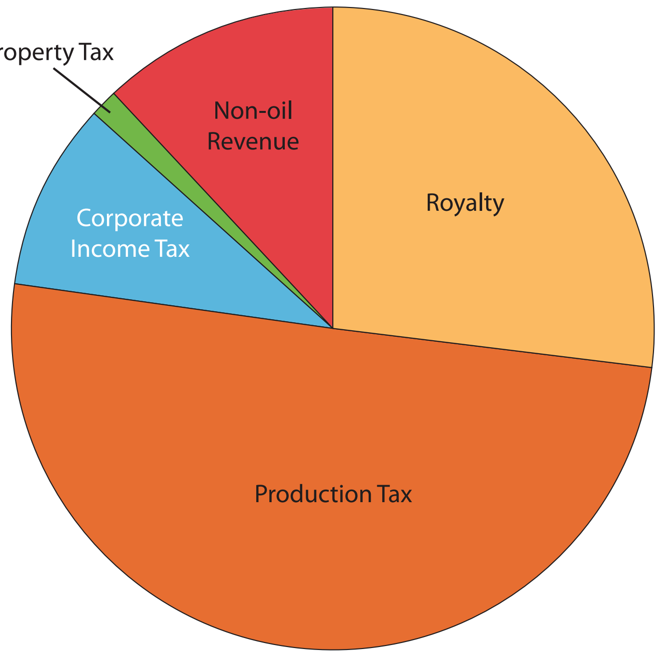

Chart depicts estimated unrestricted fiscal year 2009 general state revenue; it does not include federal revenue received by the state.

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● PIPELINES & DOWNSTREAM

Damper on Asian link

Kinder Morgan, TransCanada and Canadian Natural Resources cool to idea that new markets for Canadian crude is an early option

By GARY PARK

For Petroleum News

Any thoughts that record shipments of Canadian crude oil from the Port of Vancouver might speed up the introduction of tanker traffic on a large scale to Asia have been downplayed by Kinder Morgan Canada.

Rival pipeline companies, Enbridge and TransCanada, agree that opening the door to alternative markets is a complicated matter and might still be several years away.

Even so, there has been a sharp rise in exports from Kinder Morgan's Westridge Marine Terminal in Vancouver, with volumes hitting a record 134,000 barrels per day in March, before slipping to 55,000 bpd in May, which was still 167.7 percent above a year earlier.

Kinder Morgan anticipates an average 70,000 bpd will be loaded at its terminal.

The majority of volumes shipped by tanker from Kinder Morgan's 300,000 bpd Trans Mountain pipeline from Alberta are destined for California, with some going to the U.S. Gulf Coast through the Panama Canal, some sent for refining in Chile and Asia taking up to 10 million barrels last year.

The company does not provide a detailed breakdown of what crude finishes up where, saying that is a matter for the shippers.

Expansion could come sooner

Ian Anderson, president of Kinder Morgan's Canadian subsidiary, told a Calgary conference on unconventional oil the record movements from Westridge "very well might" lead to expansion of the terminal sooner rather than later.

"We're moving to develop markets today and those movements are happening in increasing numbers," he said.

Anderson said the rise in exports reinforces the prospect of a larger pipeline from Alberta to the British Columbia coast to new markets for Canadian crude from the oil sands and to reduce Canada's dependence on the U.S. as its exclusive export destination.

Already, Kinder Morgan has almost doubled the size of tankers it loads at Westridge, moving from Panamax-size vessels to Aframax ships which are capable of carrying 650,000 barrels and yield savings of 50 cents per barrel for customers shipping to Asia. In the next few years, the terminal could start handling Suezmax-type tankers, which can hold 1 million barrels and trim $1.50 per barrel from shipments to Asia.

Those growing ship sizes and incremental additions to Kinder Morgan's pipeline to Vancouver are consistent with supply-demand economics and are expected by the company to meet needs over at least the next decade.

The Trans Mountain system was recently boosted to 300,000 bpd from 225,000 bpd.

Kinder Morgan has two more incremental expansions available to the south coast of British Columbia, supporting deliveries to its marine exports as well as to Washington State refineries.

These are the cheapest additions, with 25 percent of the pipeline already in the ground, although there are no commercial agreements in place to make regulatory applications.

A spokesman for Kinder Morgan said the regulatory filings can proceed relatively quickly and will likely occur in lockstep with longer-term crude supply deals between Canadian producers and customers.

"Oil is a very strategic resource in North America. That tension between what Canada wants to do from a producing perspective and what North America wants to do from a strategic perspective will be the tensions that we need to deal with over time."

—Russ Girling, TransCanada's president of pipelines

For now, Kinder Morgan is focused on attaining maximum capacity of 700,000 bpd at Westridge, unless customers make a case for using VLCC, very large crude carrier, tankers from the northern British Columbia port at Kitimat to access Asian markets.

The company has talked in preliminary ways about a 400,000 bpd, 450-mile extension of its Trans Mountain system to Kitimat, while industry sources have speculated it might hold an open season in 2010.

But the company's latest view is influenced by the slowdown in production growth, combined with 1 million bpd of new pipeline capacity from Canada to the PADD II region in the Lower 48.

While keeping its options flexible, Kinder Morgan views Kitimat as a "great northern port option," said Anderson, agreeing with Enbridge that Kitimat is viable and attractive.

Enbridge more enthusiastic

Enbridge has shown more enthusiasm for an earlier start at Kitimat, and may hold an open season later this year to test shipper backing for its planned 525,000 bpd Northern Gateway pipeline.

However, Al Monaco, Enbridge's executive vice president of major projects, told the Calgary conference that the current supply profile no longer points to an immediate need for a project like Northern Gateway.

"This is certainly a forward-looking project," he said. "It's long term, based on getting to the markets over time."

Monaco said Enbridge estimates it would take three years to build the pipeline and terminal facilities after a regulatory process taking as long as two years, pointing to a post-2015 startup for Northern Gateway.

On the more positive side, Enbridge estimates the premium paid for crude from the oil sands would generate $5-$6 extra profit for every barrel shipped to Asia rather than the United States.

"That right there is the critical issue," he said. "It's being able to access other markets to maximize price."

Leverage with U.S. refiners

Russ Girling, TransCanada's president of pipelines, said companies promoting projects such as Northern Gateway are hoping to use the threat of exports to countries like China as leverage to obtain better pricing terms from U.S. refiners.

He conceded that an alternative outlet would be positive by giving producers some negotiating leverage, but that goal would be offset by North America's security of supply concerns and its eventual goal of energy self-sufficiency.

"Oil is a very strategic resource in North America," he said. "That tension between what Canada wants to do from a producing perspective and what North America wants to do from a strategic perspective will be the tensions that we need to deal with over time."

Girling said the U.S. government looks on Canada as a "domestic supply and would like to see that oil stay on the continent, if possible."

To that end, he said TransCanada believes there is more to be gained from completing its Keystone pipeline link from the oil sands to the U.S. Gulf Coast.

Cocktails for Gulf Coast

John Langille, vice chairman of Canadian Natural Resources, echoed that thought, saying his company's preferred destination for its heavy oil and synthetic crude is the Gulf Coast, which underscores why it has developed "cocktails" of heavy oil and bitumen blended with lighter oils to meet the specific needs of U.S. refineries.

He said pipelines such as Keystone are developing fresh opportunities for Canadian producers to compete against oil from Mexico and Venezuela.

"I think we will have a bit of a step change if we can get our oil down to the Gulf Coast," Langille said. "The more oil we can push down there, the more our overall price differential (or discount to light oil) will decrease just because of the marketplace we're selling into," he said.

Wenran Jiang, research chairman of the University of Alberta's China Institute, told the Calgary Herald there is a reluctance on the part of China's authorities to do deals with Canada, adding he expects China will hold off on major investments until Canadian producers take steps to provide long-term stable supplies.

For that reason, he said plans for pipelines to tanker ports in British Columbia will "remain very conceptualized." ●

GOVERNMENT

Alaska Legislature looks at gas tax

The Alaska Legislative Budget and Audit Committee has issued a request for proposals for economic analysis and modeling for Alaska natural gas taxation, estimating up to $500,000 for a contract to run through June of 2010.

The RFP notes that the state administration "is contemplating a variety of scenarios" that might change taxes on natural gas, changes that "may or may not" include decoupling gas tax rates from oil taxes.

The RFP notes that the state administration "is contemplating a variety of scenarios" that might change taxes on natural gas, changes that "may or may not" include decoupling gas tax rates from oil taxes.

Work is scheduled to begin Sept. 1 and to continue through June 30, 2010, depending on term of the Legislature, timing of administration proposals and other factors not within the control of LB&A.

Preparatory work includes reviewing and analyzing the state's current oil and gas tax regime; comparing that to other tax structures; beginning to establish parameters for "maximizing basin value" to Alaska "while maintaining sufficient incentives for exploration and development."

Once the administration presents proposed changes in the gas tax the contractor would analyze the proposed structure and its effect on revenue and "incentives or disincentives to exploration at various prices and costs" and possibly further analyze or revise the model and conduct alternative runs of the model.

The RFP specifies that firms must not have a conflict of interest arising from work done for the administration or for BP, ConocoPhillips, ExxonMobil, TransCanada, Anadarko, the Alaska Gasline Port Authority or the Alaska Natural Gas Pipeline Authority, and must "indicate any possible conflicts not specifically listed above."

—PETROLEUM NEWS

● FINANCE & ECONOMY

WTI in year's 2nd half to average $70

Natural gas usage in US down; gas storage expected to end injection season at historic high; natural gas drilling activity down

PETROLEUM NEWS

Crude oil prices rose in June for the fourth consecutive month, and were expected to average near $70 per barrel through the second half of 2009, the U.S. Department of Energy's Energy Information Administration said July 7 in its short-term energy outlook.

EIA said the rise in crude oil prices in June was partly due to "stronger-than-anticipated economic activity, primarily in Asia." The agency said expectations of economic recovery and future rebound in oil demand "are outweighing weak current oil consumption and high inventory levels."

The monthly average Henry Hub natural gas spot price, given plentiful U.S. natural gas supplies and weak demand, is expected to remain below $4 per thousand cubic feet until late in the year, the agency said, with the price expected to average $4.22 this year and $5.93 next year, based on expected economic growth.

U.S. consumption of liquids fuels and other petroleum products is projected by EIA to decrease 650,000 barrels per day, 3.3 percent, this year — including a 7 percent decline in distillate fuel consumption and an 8.7 percent decline in jet fuel consumption.

2008 domestic crude oil production averaged 4.96 million bpd, down from 5.06 million bpd in 2007 and is expected to increase to 5.23 million bpd this year and to 5.36 million bpd in 2010.

EIA said production from new federal offshore fields in the Gulf of Mexico — Thunder Horse, Tahiti, Shenzi and Atlantis — is expected to account for 14 percent of Lower 48 crude oil production by the fourth quarter of 2010.

West Texas Intermediate crude oil prices are expected to average $60.35 per barrel this year, down from $99.57 per barrel last year, and to increase to $72.42 per barrel in 2010, EIA said, a $2- to $5-per-barrel increase over the June forecast.

Gas consumption declining

The agency projects that U.S. natural gas consumption will decline by 2.3 percent in 2009 and remain unchanged in 2010; poor economic conditions are expected to prolong the current slump in natural gas demand.

Total U.S. marketed natural gas is expected to decline by 0.6 percent this year and by 2.9 percent in 2010. Natural gas producers have responded to the decrease in consumption and prices with a reduction in drilling. EIA said Baker Hughes is showing a reduction of 57 percent in working natural gas rigs since September 2008. The production decline from the drop in working rigs is expected to occur almost exclusively in the Lower 48 non-Gulf of Mexico region during the second half of this year, the agency said.

"While the drop in natural gas drilling rigs is expected to result in lower natural gas production in 2010, recent improvements in drilling technology have lowered costs, reduced drilling time, and increased well productivity. These factors should improve the responsiveness of producers to changes in demand, limiting the extent of sustained upward price movements through the forecast period," EIA said.

LNG imports to rise

U.S. imports of liquefied natural gas are expected to increase to about 506 billion cubic feet this year, up from 352 bcf in 2008 because of weak demand and growing global LNG supply. EIA said lower demand for LNG in Japan and South Korea has increased the available amount of LNG, leading to larger LNG purchases in China and Europe, but "with limited natural gas storage capacity in Asia and Europe, lower global demand is expected to increase available LNG cargoes for import by the United States."

On June 26 working natural gas storage in the U.S. was 2.721 trillion cubic feet and inventories were 467 bcf above the five-year average. Through the first three months of the injection season (March 27 through June 26) the estimated inventory build was 1.067 tcf, the largest increase for the period since 2001, EIA said.

Working natural gas storage is expected to reach 3.67 tcf by Oct. 31, the end of the injection season, some 105 bcf above the previous record of 3.565 tcf reported at the end of October 2007.

EIA said the Henry Hub spot price, which averaged $3.91 per thousand cubic feet in June, continued to reflect "the disparity between weak demand and strong supply."

U.S. natural gas production is expected to decline in the coming months, but "historically high storage levels and limits to storage capacity may cause prices to decline further this fall," the agency said. EIA projects natural gas price recovery early next year as the market balance tightens, but said "rising prices are expected to be tempered by improvements in the productive capacity of domestic onshore supply sources throughout the forecast period." ●

EXPLORATION & PRODUCTION

Dirt again rising at oil sands site

Connacher Oil and Gas has resumed construction at a second steam-driven oil sands project in the Great Divide region of northeastern Alberta, seven months after suspending work because of slumping oil prices and tight credit markets.

Analyst Lanny Pendill said the fact that such a small company (Connacher has so far produced 3.3 million barrels at 8,000 bpd from its initial phase) was able to secure financing is a sign that capital markets are loosening up.

Having successfully completed a C$200 million debt offering a month ago, Connacher said the C$350 million, 10,000 barrel per day Algar project is back on track. So far, C$150 million has been invested, mostly for off-site fabrication of plant components and equipment.

Construction is scheduled for completion by late 2010 as Connacher achieves another milestone on the way to its targeted 50,000 bpd by 2015.

The company said recent operating costs have slipped under C$15 per barrel and increased volumes would contribute to further reductions.

It said the wave of project cancellations or deferrals in the oil sands region may have lowered the costs of labor, services and equipment.

Analyst Lanny Pendill said the fact that such a small company (Connacher has so far produced 3.3 million barrels at 8,000 bpd from its initial phase) was able to secure financing is a sign that capital markets are loosening up.

He said the partial recovery in oil costs and lower capital costs has put the oil sands sector "pretty much on the cusp," bolstered by Imperial Oil's decision to go ahead with its C$8 billion Kearl project.

The threshold for reviving projects is confidence that oil prices will not drop much below US$60 per barrel.

William Lacey, an analyst with FirstEnergy Capital, said there are strong indications that debt markets have opened up again, with Talisman Energy, Husky Energy and Canadian Oil Sands Trust all raising debt under 8 percent.

—GARY PARK

● NATURAL GAS

Kitimat LNG lines up first gas producer

By GARY PARK

For Petroleum News

Progress in assembling the necessary underpinnings of the Kitimat LNG project has made another large stride forward with the privately held company signing its first supply deal with a Western Canadian producer.

Although the volumes involved have yet to be negotiated, Kitimat LNG has reached a memorandum of understanding with EOG Resources, which has a major stake in British Columbia's Horn River shale gas region.

EOG holds 157,500 net acres of exploration land in Horn River, where it is keeping up the pace of drilling this year, while drastically reducing its shallow gas program in Western Canada.

One of the top 10 gas producers in Canada, EOG has reserves of 1.3 trillion cubic feet — a 15-year proven reserve life — and is one of the most upbeat forecasters for Horn River, which Kitimat LNG is eying as a key potential source of gas to reach the minimum 700 million cubic feet per day it estimates is necessary to proceed with the LNG project.

So far, Korea Gas and Spain's Gas Natural have memorandums of understanding to take 40 percent and 30 percent respectively of the Kitimat terminal's initial capacity.

Kitimat LNG President Rosemary Boulton said in a statement that EOG's participation "reinforces the fact that business and natural gas fundamentals support our LNG terminal," planned for British Columbia's deepwater port at Kitimat.

"Kitimat LNG presents a compelling opportunity for producers to leverage growing natural gas reserves in Western Canada and sell into significant new international markets such as Asia," she said.

Boulton said talks are under way with about 10 Canadian producers as well as potential terminal users and LNG buyers.

She said the project could be onstream by late 2013, depending on how quickly commercial arrangements can be finalized.

To achieve that goal, front-end engineering design study may have to start by this fall, allowing construction to start in spring 2010.

Bill Gwozd, vice president of gas services at Ziff Energy Group, said the presence of EOG could be a vital stepping stone for Kitimat LNG and gives EOG opportunity to diversify its markets at a time when North American gas prices are in a slump. ●

NATURAL GAS

Alberta wrestles with gas flaring

The Alberta Energy Resources Conservation Board estimates that flaring and venting of waste gas associated with oil production rose 7.6 percent last year to about 25.7 billion cubic feet. A spokesman for the regulator said the increase largely stems from higher rates of bitumen drilling.

Despite the rise, solution gas flaring in Alberta has been lowered by 77 percent since 1996 and solution gas released into the atmosphere is down 41 percent since 2000.

The board's report indicates the upstream oil and gas industry conserved 95.1 percent of all solution gas produced in Alberta last year for use or sale, rather than flaring and venting.

The Alberta government set a goal 10 years ago of virtually eliminating flaring and venting of solution gas, and, despite the success so far, the board is consulting with various groups on further regulatory changes.

—GARY PARK

● PIPELINES & DOWNSTREAM

TAPS transitioning to low flow future

Strategic reconfiguration of the trans-Alaska pipeline moves ahead, while engineers assess the challenges of declining flow rates

By ALAN BAILEY
Petroleum News

At the end of May, the switchover to new electric pumps at pump station 4 of the trans-Alaska oil pipeline marked the latest major step in the upgrade of the pipeline system to accommodate declining rates of oil production from Alaska's North Slope. In fact, the decline of flow rates from 2.1 million barrels per day in 1988 to around 700,000 bpd at present and a likely 500,000 bpd in the next decade poses one of the biggest challenges faced by Alyeska Pipeline Service Co., the pipeline operator, said Kevin Hostler, Alyeska president and CEO, at a media presentation on July 13.

Hostler said that the installation of electric pumps, part of a project that Alyeska refers to as "strategic reconfiguration," is matching pumping power to throughput volumes, but that other challenges resulting from low flow rates, such as low oil temperatures, also need to be addressed.

"We've put a smaller engine now on a bigger car and, so, there are still other issues associated with lower throughput," Hostler said.

The trans-Alaska oil pipeline, characterized by Hostler as a simple pipeline, albeit with an exceptionally large diameter of 48 inches, crosses three mountain ranges along its 800-mile route from Prudhoe Bay on the North Slope to Valdez, on the northeastern side of Prince William Sound. At the Valdez Marine Terminal, oil is loaded into tankers that ply the sea route down to the U.S. West Coast.

Five companies own both Alyeska and the pipeline: BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska Inc., ExxonMobil Pipeline Co., Koch Alaska Pipeline Co. and Unocal Pipeline Co.

Fewer pump stations

Perhaps the most obvious evidence of the "smaller engine" that Hostler referred to is the reduced number of pump stations along the pipeline.

Of the original 11 pipeline pump stations used to move oil during peak throughput, only five remain in use. Three of these remaining stations — pump station 1 at the northern end of the


ALYESKA PIPELINE SERVICE CO.

Located in the foothills of the Brooks Range, pump station 3 was the second pump station to begin using new electrical pumping equipment and control systems. The green buildings in the foreground house the new pumps.

pipeline, and pump stations 3 and 4 — propel the oil up to the 4,739-foot Atigun Pass in the Brooks Range. From this high point the oil flows downhill 350 miles south to pump station 9, near Delta Junction. Pump station 9 drives the oil over mountain passes in the Alaska and Chugach ranges, with the oil eventually flowing down into storage tanks in the Valdez Marine Terminal.

Pump station 5 on the south side of the Brooks Range does not pump the oil: It acts as a relief station for oil flowing down from Atigun Pass.

Under strategic reconfiguration, a train of new centrifugal pumps, each driven by a purpose-built 6,500-horsepower electric motor, replaces the turbine-powered pumps that were installed at each pump station when the pipeline was first constructed. Whereas the old pumps had limited capabilities for power adjustment and could not operate at very low flow rates, the new pumps use variable frequency drives and can be switched in and out of operation, thus enabling great flexibility in handling different levels of pipeline throughput.

One at a time

As part of a plan to switch the pump stations over to the new technology, one station at a time, Alyeska applied the on switch to the new pumping system at pump station 9 in February 2007, with the required electrical power flowing from the local electric utility — a backup, on-site generator could plug the power-supply gap, were the utility to experience a blackout.

Pump station 3 started its electric pumps in December 2007, and now pump station 4 has followed suit, both using large turbine generators for power. That leaves pump station 1 to be converted, an operation that Alyeska expects to complete in late 2011 or early 2012.

In the summer of 2008, during a pipeline shutdown, the old turbine system at pump station 9 was disconnected from the system, Alyeska senior project manager Jerry Vega told the media briefing.

"We can't go back to the old system … any more," Vega said.

And the old equipment was disconnected in pump station 3 in June of this year, he said.

Alyeska experienced problems with vibrations, both inside the new pump modules and in the pipeline itself, when the converted pump stations went on line. The pipeline vibrations resulted from the use of new pipeline supports designed to avoid the need for winter snow removal at the pump stations, said Matt Carle, Alyeska external affairs manager.

The pump vibrations have been eliminated, while the pipeline vibrations have been controlled, using steel bracing on the pipeline supports, Vega said. And the new pumps are operating well, following adjustments made to accommodate minor quirks found when operating the systems in cold winter conditions at pump station 3, he said.

"All of the different components of the system have met our performance criteria," Carle said.

New control systems

In parallel with upgrading the pumping systems along the pipeline, Alyeska has been engaged in a complete replacement of the aging pipeline control sys-

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TAPS FUTURE

tems, using state-of-the-art digital technology to enable monitoring and control of the entire pipeline from a single control center and the collection of data for improved maintenance efficiency, thus reducing operations and maintenance costs as oil volumes decline.

And as part of the control systems upgrade, in early 2008 Alyeska moved the pipeline control center from Valdez to Anchorage, with modern fiber optic telecommunications, backed up by a microwave system, used to transmit data and control commands up and down the pipeline.

One section of the control center manages the pipeline while another section manages the Valdez Marine Terminal, Betsy Haines, Alyeska oil movements director, told the media briefing. There is also a duplicate, backup control center at a secret location in the Matanuska-Susitna Borough, she said.

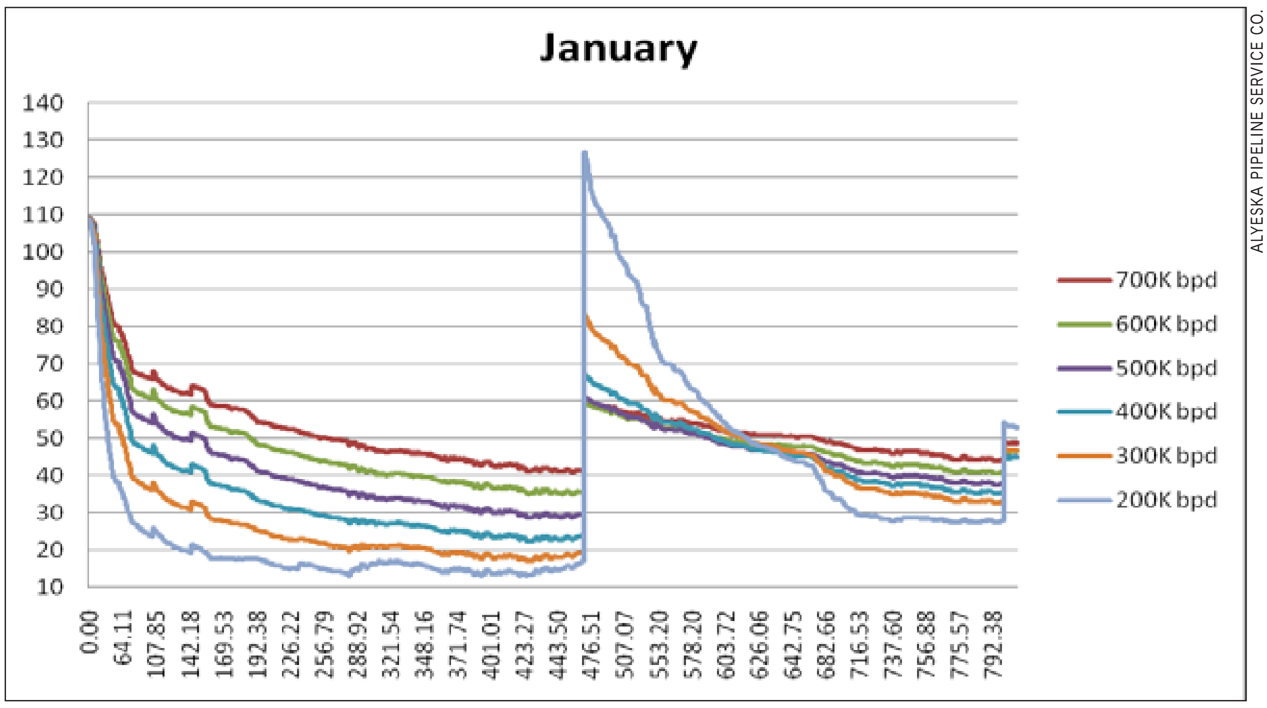
All of the pump stations, including pump station 1, are now fully controlled from the control center, as distinct from being operated by on-site pump station personnel, Haines said.

"The requirement for any operator support now is primarily at pump station 1, strictly from the point of view of observation as the equipment starts up," she said.

And, apart from pump station 1, where personnel will always be required for situations associated with operating the storage and oil intake arrangements at the upstream end of the pipeline, centralized control of the pipeline system is leading to de-manning of the pump stations, with just oil spill response and maintenance crews remaining at some pump stations, ready to deploy in the event of an emergency.

Pump stations 9 and 3 are already fully unmanned from an operations perspective, and the living quarters were removed from pump station 3 this summer, Vega said.

The site of the long-defunct and dismantled pump station 8, between Fairbanks and Delta Junction, has found a new role in helping deal with increased wax deposition within the pipeline, as the flow of oil through the line declines. This summer Alyeska is installing new equipment at the site to enable retrieval, cleaning and reinsertion of pigs, torpedo-shaped devices used to clean wax from inside the line, during the devices' 800-mile journeys from Prudhoe Bay to Valdez — currently the pigs can only be retrieved at pump station 4, towards the northern end of the pipeline, Vega said.



ALYESKA PIPELINE SERVICE CO.

Alyeska Pipeline Service Co.'s projections of likely oil temperature profiles along the entire trans-Alaska pipeline at different oil flow rates. At a flow rate of 500,000 barrels per day, the oil temperature will likely drop below the freezing point of water at some places along the pipeline route. The sharp jumps in temperatures at around miles 476 and 762 mark points at which refineries along the pipeline return residual material to the pipeline at elevated temperatures.

Valdez Marine Terminal

Declining pipeline throughput is also having a major impact at the Valdez Marine Terminal.

The terminal is currently using 15 of the 18 original crude oil storage tanks, senior project manager Curtis Nuttall told the media briefing.

"In the future we plan on dropping it down to eight to 12 tanks," Nuttall said.

And just two of the original four tanker loading berths continue in operation.

"We are currently overhauling those (operational) berths," Nuttall said.

And the mandated use of double-hulled tankers at Valdez, as well as the reduced oil throughput, has dramatically reduced the amount of ballast water from arriving empty tankers that needs to be treated.

"The tanker operators elected not only to double-hull, but to use segregated hulls for their ballast (water), which means they don't have dirty ballast," Nuttall said.

Previously, the ballast water went into the crude hold, thus contaminating the water and making it necessary to treat the water on removal from the tanker.

Years ago, with the old tankers and large numbers of tanker operations, the processing of perhaps millions of gallons of ballast water per day involved floating the oil from the water, then using air bubbles to float out further oil and finally using bacterial treatment to eliminate any remaining hydrocarbons, before discharging the treated water into the sea.

However, as the ballast water throughput declines, the bacterial treatment becomes ineffective because the bacteria tend to starve.

"So what we've had to do is replace that whole large

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TAPS FUTURE

biological system with air strippers," Nuttall said.

And Alyeska is engaged in a three- to four-year, $100 million retrofit of the entire ballast water plant, including the installation of vapor control equipment, equipment not legally required but viewed by Alyeska as a safety need, Nuttall said.

Low flow

However, Alyeska foresees further technical challenges along the pipeline system as oil throughput continues to go down: The company has initiated a $10 million low-flow study, to find solutions to the various issues involved.

The study started in August 2008 and is slated for completion at the end of 2010, Pat McDevitt, the low-flow study project manager, told the media briefing.

"As the flow rates decline, the transit time for the oil to travel increases," McDevitt said. "So, at 2 million barrels per day … it took four and a half days or so to get from pump station 1 to Valdez. Right now it's about 13 days. … At 500,000 barrels per day it's about 18 days."

The declining velocity of the oil causes the flow to become less turbulent, thus increasing the likelihood of any water and sediment in the oil dropping out. And, because the oil remains in the pipe longer at low flow rates, the oil becomes colder as it traverses the line — at a throughput of 500,000 barrels per day, Alyeska expects the oil temperature to drop below 32 F, the freezing point of water, along some pipeline segments, McDevitt said.

Most water is removed from the crude oil before the oil enters the trans-Alaska oil pipeline, but a small amount of residual water remains in the oil, McDevitt explained. And although the water is saline, ice formation within the pipeline or associated equipment could cause problems, while the salty water and sediment separated from the oil could heighten the risk of internal pipeline corrosion.

In addition, the lowering temperatures will further increase the amount of wax deposited in the pipeline from the oil, thus increasing the amount of pipeline and tank cleaning required.

And cold oil could change the thermal characteristics of the ground around the pipeline, potentially causing frost heaves that could move the pipe.

McDevitt characterized the low-flow study as science research that is proceeding along several fronts, such as flow testing in a test rig in a special cold room at Imperial Oil's facility in Detroit, and the testing of ice formation and ice strength in sample oil that is cooled down.

Possible solutions to pending problems include tightened limits on the amount of water allowed in the pipeline; adding chemicals to prevent wax deposition; increased pigging for wax and water removal; heating of the oil at certain points on the line; and the use of freeze-suppressant chemicals.

Corrosion

But given the pipeline corrosion problems and associated leaks in the aging oilfield infrastructure at Prudhoe Bay, where low oil flow rates have also become an issue, how confident is Alyeska that similar problems can be avoided in the trans-Alaska pipeline?

To prevent corrosion, which has proved in the past to be less of a problem on the inside of the pipeline than on the pipeline exterior, the pipeline has a protective coating; there are cathodic protection systems for pipelines and tank bottoms; corrosion inhibitors are mixed with the oil; and pigs are used frequently to clean the inside of the main pipeline, Tom Webb, Alyeska's engineering integrity manager, told the press briefing.

"We run cathodic protection surveys on an annual basis … to measure the level of protection to the buried metallic piping structures," Webb said. There are test stations every half mile on the pipeline, he said.

Alyeska runs a magnetic flux leakage pig down the line every three years to obtain a profile of precise pipeline wall thicknesses and hence determine where corrosion is occurring. And every five years another type of instrumented pig detects any changes in pipeline shape.

"We've got locations of every corrosion point on the pipeline," Webb said. "We know the magnitude of that corrosion."

Successive runs of the magnetic flux leakage pig enable engineers to trend and map the corrosion, enable people to determine where the corrosion is focused and then take any necessary actions such as reviewing the cathodic protection levels, or repairing the line.

Facilities in the pump stations that cannot be accessed by a pig are subject to regular inspections under a pipeline integrity testing program — more than 800 inspections are scheduled for 2009 under this program, Webb said. Tanks are also inspected regularly.

"We have had no corrosion leaks in over 30 years of service on TAPS to date, and we intend to keep it that way," Webb said. ●

On the Web

See previous Petroleum News coverage:

"Alyeska takes the next strategic step," in Aug. 31, 2008, issue at www.petroleumnews.com/pnads/549251260.shtml

"New pumps start up at Pump Station 3," in Dec. 23, 2007, issue at www.petroleumnews.com/pnads/244022826.shtml

"TAPS switches to 21st century," in March 4, 2007, issue at www.petroleumnews.com/pnads/784169373.shtml

NATURAL GAS

Hints of big Horn River strike

A partnership of parent company and offspring, ExxonMobil and Imperial Oil, is playing it coy on results from its exploration debut in British Columbia's Horn River shale gas play, despite hints of something big.

An ExxonMobil executive told the Wall Street Journal that initial rates have been in the range of 16 million to 18 million cubic feet per day; a company spokesman later said tests of the first two wells drilled last winter flowed at about 2 million cubic feet per day, with the company issuing an e-mail saying the test wells "did not flow anywhere near the stated rates." Imperial (owned 69.6 percent by ExxonMobil) declined to confirm any numbers.

The Horn River test wells were drilled vertically and the well bore was punctured by a single perforation, while production wells are initially drilled vertically, then directed horizontally, when eight or more fracture intervals are made.

The 50-50 partnership has joined an industrywide land rush into northeastern British Columbia, assembling a sizeable land position over the past two years, rating the play as a "new opportunity with considerable resource potential."

William Lacey, an analyst with FirstEnergy Capital, said ExxonMobil's involvement is "another endorsement for the region," but he noted the supermajor focus on profit rather than return on capital suggests the company is not going to "rush out to develop."

The Horn River test wells were drilled vertically and the well bore was punctured by a single perforation, while production wells are initially drilled vertically, then directed horizontally, when eight or more fracture intervals are made.

Current production from Horn River is only about 100 million cubic feet per day, about 2.5 percent of flows from the prolific Barnett shales in Texas and less than 1 percent of Canada's total output.

—GARY PARK

PIPELINES & DOWNSTREAM

Rockies shouldering Canadian gas aside

A new pipeline carrying cheap natural gas from the U.S. Rockies threatens to displace about 10 percent of Canadian exports to the Midwest, swelling gas in storage and eating into returns for Canadian producers.

The Rockies Express line, covering 1,680 miles, ships 1.5 billion cubic feet per day through the Midwest to Ohio.

Although the latest section of the so-called REX system only came into service in late June, it has already shut out about 600 million cubic feet per day of Canadian exports.

REX, a partnership of Kinder Morgan, Sempra Energy and ConocoPhillips, is designed to eventually handle 1.8 billion cubic feet per day.

Cheaper than Canadian gas

Rockies gas is cheaper than supplies from Canada and REX is a more efficient carrier than the long-established Northern Border pipeline, which originates in Alberta.

A further threat to Canada's traditional role as the supplier of about 15 percent of U.S. gas consumption is the rapidly accelerating use of new technology to drill for unconventional gas in Montana, Wyoming and Colorado.

Despite the vast deposits in British Columbia's Horn River and Montney plays, the challenge for Canadian producers is to get gas out of the ground for less than US$4 per thousand cubic feet if they hope to retain even their current shrinking share of the U.S. market.

—GARY PARK

FINANCE & ECONOMY

Oil industry cranks up lobbying effort

Oil, gas spending in D.C. up more in past 2 years than other industries; $129M spent in '08; $44.5 million in 1st quarter of '09

By JOHN PORRETTO

Associated Press Energy Writer

Oil and gas companies have accelerated their spending on lobbying faster than any other industry, training their gusher of profits on Washington to fight new taxes on drilling and slow efforts to move the nation off fossil fuels.

The industry spent $44.5 million lobbying Congress and federal agencies in the first three months of this year, on pace to shatter last year's record. Only the drug industry spent more.

Last year's total of $129 million was up 73 percent from two years earlier. That's a faster clip than any other major industry, according to data from the Center for Responsive Politics.

From the late 1990s through the first half of this decade, the oil industry spent roughly $50 million to $60 million a year on lobbying. It ramped up lobbying in 2006, when Democrats retook Congress, and further as President Barack Obama took office.

"They're under attack, they're ramping up their operations and they've got money to spend," said Tyson Slocum, who runs the energy program at watchdog group Public Citizen. "They're in much better position than other industries to draw upon financial resources for their lobbying effort."

Industry a target

Billions of dollars in oil profits in recent years have made the industry a target for new and higher taxes on exploration and drilling. Oil companies and refiners are also trying to blunt the impact of costly climate change legislation pushed by Obama.

While most oil and gas executives acknowledge the nation needs cleaner energy, they say lawmakers are misguided about how quickly it can happen. They warn that taxes and tighter rules on exploration could cripple the industry before new technology is developed.

Complex issues like that "require additional communication and effort to ensure lawmakers understand our positions," said Alan Jeffers, a spokesman for Exxon Mobil Corp., the world's largest publicly traded oil company.

ExxonMobil was the biggest spender in the first quarter, pumping $9.3 million into Washington — three times what it spent a year ago, according to House disclosure reports.

In its House filing, Exxon noted it lobbied on high-profile topics like climate and tax legislation as well as provisions regarding the chemical industry, education and health care.

Majors and independents spending

Combined, the three largest U.S. oil companies — Exxon, Chevron Corp. and ConocoPhillips — spent about $22 million on lobbying in the first quarter. Smaller, independent companies that produce the bulk of the nation's crude and natural gas are spending millions, too.

They're spending more even as profits have subsided. The big three U.S. oil companies spent just $12.4 million on lobbying in the fourth quarter.

First-quarter spending on lobbying by the oil industry trailed only drugmakers and health products companies, which spent $66.6 million.

"I can tell you, I've had substantially more visits than usual," said Rep. Gene Green, whose south Texas district is in the heart of oil country. Among his callers, he said, have been representatives of ConocoPhillips and ExxonMobil to discuss climate-change legislation and other matters.

To a degree, the investment appears to be paying off. In mid-June a Senate committee voted to lift a ban on drilling across a vast area in the eastern Gulf of Mexico.

see **OIL LOBBY** *page 13*

NATURAL GAS

ANGDA's third report to people in video

The Alaska Natural Gas Development Authority released its third report to the people July 15. The authority's first two reports were printed and were distributed in newspapers.

This report is a video and is available online.

ANGDA said the new report details the authority's project achievements thus far in its work to deliver Alaska's natural gas to Alaskans.

The video, which runs 16 minutes, is at www.ourgas.us.

—PETROLEUM NEWS

Many industries spending more on lobbying

Here's the rate at which major industries increased spending on lobbying in Washington between 2006 and 2008:

- Oil & Gas: 73 percent
- Air Transport: 59 percent
- Electric Utilities: 43 percent
- Pharmaceuticals/Health Products: 29 percent
- Business Associations: 24 percent
- Misc. Manufacturing & Distributing: 21 percent
- Education: 17 percent
- Hospitals/Nursing Homes: 16 percent
- Insurance: 14 percent
- Computers/Internet: 4 percent

Source: Center for Responsive Politics, disclosure filings with U.S. Senate.
The Associated Press

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OIL LOBBY

The provision, which the industry pushed for, is included in a bill that would expand the use of renewable energy sources such as wind and solar. The bill now goes to the full Senate.

Democrats from oil states have also managed to get rid of a provision in an anti-pollution bill that would have required refiners to meet a standard on low-carbon motor fuel. Refiners say the bill would still be devastating to business.

Most major industries have increased what they spend on lobbying, but no one has done so at a faster clip over the past two years than oil and gas companies, according to data from the Center for Responsive Politics.

Spending and the hot seat

The enormous amount of money funneled to Washington by energy companies comes after some members of Congress suggested slapping the big oil companies with a windfall profits tax last year, when Americans were seething over $4-a-gallon gas.

Democrats — who also took the majority of state legislatures and governorships in 2006 — traditionally have not been as cozy with the oil sector as Republicans, and the energy lobby has spent the past few years trying to make inroads.

"You'll often see a correlation between spending and an industry or company that's in the hot seat," said Sheila Krumholz, the Center for Responsive Politics' executive director. "That will be enough to get them to hire additional guns and direct more money to lobbying."

Sean Brodrick, a natural resources analyst at Weiss Research Inc., cited the coal lobby as an example of one that's already had some success with the Obama administration.

He noted a futuristic coal-burning power plant in Illinois that languished under the Bush administration has now found favor with Obama Energy Secretary Steven Chu. The Energy Department will commit more than $1 billion to the project under an agreement announced last week.

"I think (the Obama administration) will make some accommodations," Brodrick said. "They may speak really tough before these laws are enacted, but you watch, I bet the energy companies will have some effect in actually shaping how these laws finally come out of the big sausage factory." ●

FINANCE & ECONOMY

Canadian trust tackles debt

In a debt-trimming mission, True Energy Trust has unloaded 3,000 barrels of oil equivalent per day (75 percent heavy oil) and natural gas properties to Baytex Energy Trust for C$93 million.

The heavy oil properties are in two areas of southwest Saskatchewan. Interests in almost 2,000 acres of west-central Alberta properties are also included in the deal.

The package includes 5.3 million cubic feet per day of natural gas production, seismic data and 63,000 net acres of undeveloped mineral leases, True said.

In a separate transaction, True sold 145 barrels of oil equivalent per day in central Alberta for C$4.75 million. Following closure of the sales, expected by July 30, True's total net debt is expected to be about C$110 million and its production is forecast at 6,500 barrels of oil equivalent per day, comprising 32 million cubic feet per day of gas and 1,230 bpd of light and medium oil.

It will also hold 275,000 net undeveloped acres and 320 drilling locations.

Baytex expects to boost its output to 43,000 barrels of oil equivalent per day.

It said the Saskatchewan heavy oil assets hold many opportunities for cold infill drilling and steam-assisted development.

—GARY PARK

NATURAL GAS

RCA sets technical conference on CI gas

The Regulatory Commission of Alaska decided during its July 15 public meeting to hold a technical conference in late August, to gather ideas on Cook Inlet utility gas pricing. The commission is trying to determine how to address the contentious issue of reviewing utility gas supply contracts as part of the approval process for gas and electricity utility tariffs — in May the commissioners had agreed to initiate a regulations docket on this topic by issuing a public notice of enquiry, but that notice has not been issued and the docket has not yet been opened.

Much of the discussion in the July 15 public meeting revolved around the question of how to achieve legal clarity regarding RCA jurisdiction over the Cook Inlet utility gas supply contracts.

"We might benefit, before opening the formal docket, from a technical conference, either on or off the record, to determine first what persons or entities would participate in the regulations docket," Commissioner Janet Wilson said.

A conference would also provide an informal setting for people to discuss ideas about gas pricing without the commission having to first propose how it intends to address the issue, she said. On the other hand, the notice of enquiry, as conceived in May, would merely serve to gather preliminary public comments that would replicate comments that the commission has already received she said.

Legal clarity

Much of the discussion in the July 15 public meeting revolved around the question of how to achieve legal clarity regarding RCA jurisdiction over the Cook Inlet utility gas supply contracts. The commission regulates the utilities but does not regulate the gas producers that supply gas to the utilities. However, under state statutes the commission must review the gas supply contracts associated with a utility tariff revision.

After a debate regarding the relative merits of seeking an informal view of the jurisdiction issue from the state Department of Law, versus seeking a formal legal opinion from the state Attorney General, the commissioners elected to seek advice from assistant attorneys general present at the meeting, during an executive session at the end of the meeting.

Lack of agreement over acceptable gas price levels for Cook Inlet utility gas has become a major stumbling block to regulatory approval of new gas supply contracts in recent years, raising questions regarding the viability of future gas production in relation to the desire to limit energy price increases for Southcentral Alaska consumers.

—ALAN BAILEY

SAFETY & ENVIRONMENT

Meet the ocean observation scientists

The Alaska Ocean Observing System is inviting the public to meet the scientists involved in its Prince William Sound "Sound Predictions 2009" program, and to tour its research vessels, in Valdez on July 28. The meeting and tour will take place in the Valdez Convention Center and Valdez harbor between 11 a.m. and 1 p.m.

Among other activities, there will be a demonstration of new technology for balloon surveillance at night of potential oil spills. And local kids will demonstrate how their handmade remotely operated vehicles can clean up spilled oil.

AOOS says that the Sound Predictions 2009 program involves the deployment of buoys and autonomous vehicles in Prince William Sound to collect data about wind, waves and ocean circulation, to evaluate the effectiveness of regional forecast models.

"Twenty years after the Exxon Valdez oil spill, we're testing how well we know information about Prince William Sound for use in oil spill response, search-and-rescue operations, marine safety for oil tankers and recreational boaters, and fisheries and ecosystem health," AOOS said.

For further information contact Darcy Dugan, AOOS program manager, at dugan@aoos.org or 907-644-6718.

—ALAN BAILEY

● FINANCE & ECONOMY

Oil above $61 as jobless numbers drop

By CHRIS KAHN

Associated Press Energy Writer

Oil prices wavered July 16 after the government reported that jobless numbers had dropped unexpectedly.

Benchmark crude for August delivery added 9 cents to $61.63 a barrel on the New York Mercantile Exchange. In London, Brent prices fell 14 cents to $62.95 a barrel on the ICE Futures exchange.

The Labor Department said new applications for unemployment insurance dropped to their lowest level since early January. However, a department analyst said the drop reflected problems adjusting layoffs for temporary shutdowns at General Motors and Chrysler plants.

Meanwhile, government reports showed U.S. storage facilities were still bloated with unused supplies and America's appetite for petroleum continued to hover around 10-year lows.

Government reports on how much energy the country has on hand provide key readings on how well the economy is faring. This year, during one of the worst slumps since the Great Depression, U.S. inventories have been brimming with unused petroleum.

Gas stocks above average

The Energy Information Administration said July 16 that trend continued as natural gas stockpiles remained well above their five-year average, growing to about 2.89 trillion cubic feet for the week ended July 10. A day earlier, the administration said distillate fuel levels rose to their highest level in 24 years.

Mike Zarembski, Senior Commodities Analyst at OptionsXpress, said the fuel supplies continue to tell traders that prices should stay where they are.

At the pump, retail gas prices fell 1.2 cents to a new national average of $2.492 a gallon, according to auto club AAA, Wright Express and Oil Price Information Service. A gallon of gas is 18.2 cents cheaper than a month ago and $1.622 cheaper than last year.

In other Nymex trading, gasoline for August delivery added less than a penny at 1.7150 a gallon. Heating oil for August delivery climbed 2 cents to fetch $1.6024 a gallon. Natural gas for August delivery increased 22.3 cents to $3.506 per 1,000 cubic feet. ●

—Associated Press writers Ernest Scheyder in New York, George Jahn in Vienna, Austria and Alex Kennedy in Singapore contributed to this report from Singapore.

GOVERNMENT

Lougheed advises slowing oil sands pace

By GARY PARK

For Petroleum News

It's almost a quarter of a century since Peter Lougheed stepped down as premier of Alberta, after a distinguished 14 years when he laid the foundations for what remained a world model of oil and gas regulation until the government started overhauling its royalty system in 2006.

Once outside politics, Lougheed carefully avoided commenting on public policy or government decisions until the last couple of years when he has vigorously entered debate on the future directions of oil sands development.

As the most trusted voice in Alberta, he has quickly found himself on safe ground.

Without overplaying his hand, he periodically takes to the podium to deliver his increasingly popular message that the costs and environmental impact of oil sands projects can be better managed by slowing the pace of expansion.

For now, that pace is being dictated by the price of crude (with $80 per barrel seen as the minimum economic threshold), tight credit and unease over the future of North American greenhouse gas regulations — all resulting in at least C$100 billion worth of mining and in-situ projects being shelved.

Mining projects one at a time

Opening an international engineering conference in Calgary on July 14, Lougheed said the Alberta government should use the slowdown to slow the pace of growth by limiting mining projects to one at a time, thus softening the cost impact on a wide range of related businesses.

The old master showed, if nothing else, he hasn't lost his sense of political timing.

If anything can be done to slow things down it's surely now as oil sands developers start eying an economic recovery later this year or early 2010, even though most are still adopting a "wait and see" stance.

But a surge in spot oil prices, nudging US$60 in recent weeks, and a 30 percent drop in capital costs since mid-2008 are firing up speculation that cash-rich companies might be ready to revive projects at oil prices of US$60-$70 per barrel WTI, while banks probably need confidence that prices will remain above US$50 over the long term.

But, before Alberta heads into a fresh round of growth, Lougheed suggested there should be acknowledgement that the oil sands "have created in our province, because of the rapid growth that has occurred in the past decade, a very high-cost economy."

"That means we have a built-in cost factor here that is very difficult for people in other businesses and I see a growing pressure on the current government to revisit this issue."

Modestly suggesting that he holds a "minority" opinion — though he is widely viewed as the most trusted voice in Alberta — Lougheed did concede the government is well aware of his position on the oil sands.

Speed up underground recovery

Lougheed later told reporters that, while surface-mining projects should only be allowed to proceed one at a time, lower-cost underground bitumen-recovery schemes, using steam-assisted extraction methods, could move ahead at a faster pace.

On the pricing front, Lougheed tossed his 10 cents into the mix, predicting oil will return to US$100 per barrel "fairly soon … whether that is November or next April, it's going to come."

"What the past policy of the Alberta government has been is to have a number of projects going on concurrently," he said. "What I've been suggesting is that one project should be done and completed before the next starts.

"That will be hard to accomplish in the short term, because so many commitments have been made, but I would hope, in due course, the new government in Alberta would move themselves to a more uniform development," he said.

"I think public opinion is changing and there's a possibility that, when the current slowdown comes to an end, they may reassess their view."

On the pricing front, Lougheed tossed his 10 cents into the mix, predicting oil will return to US$100 per barrel "fairly soon … whether that is November or next April, it's going to come." The Alberta government, for budget purposes, is predicting US$55.50 this year, US$64.50 in 2010 and US$72.50 in 2011.

He said demand will return to growth in the United States as the economy recovers, but won't be met by traditional sources such as Venezuela (hostile to the U.S.), Saudi Arabia (declining output) or Nigeria (unreliable).

Lougheed was far less upbeat about natural gas, where demand in North America will take longer to recover than oil, "but it will and I see it competing very much in terms of electric power with coal." ●

SAFETY & ENVIRONMENT

Valdez watchdog group seeks new chief

A Valdez-based oil industry watchdog group is advertising for a new leader.

The Prince William Sound Regional Citizens' Advisory Council lost its executive director when John Devens resigned in May.

Devens had begun a medical leave of absence in February. He had been the council's executive director since 1997 and was mayor of Valdez at the time of the Exxon Valdez oil spill in 1989.

Devens had begun a medical leave of absence in February. He had been the council's executive director since 1997 and was mayor of Valdez at the time of the Exxon Valdez oil spill in 1989.

The spill spawned the congressionally mandated, nonprofit council to act as a watchdog over the Alyeska Pipeline Service Co. terminal and tanker operations at Valdez.

The oil industry provides most of the funding for the council, which has an annual budget of more than $3 million and a staff of 18 in Valdez and Anchorage.

Hunt on for new director

The council's board of directors hopes to hire a new executive director in the next three to six months, spokesman Stan Jones said.

Donna Schantz, a Valdez resident and the council's director of programs, is serving as acting executive director.

The council has 18 member organizations. Board members represent communities as well as aquaculture, commercial fishing, environmental, Native, recreation and tourism groups.

At times, the council and its staff have been sharply critical of the oil industry. The council has pushed for initiatives such as reduced air pollution at the Alyeska terminal, radar to detect icebergs that can damage tankers, and continued industry support for tanker tug escorts.

The council also monitors oil spill response capability and engages in research such as safeguarding Prince William Sound from aquatic nuisance species.

—WESLEY LOY

Business Spotlight

Alta Air Logistics

Alta Air Logistics provides innovative logistics and transportation services for clients in Alaska and around the world, offering high quality solutions for customers operating in a variety of environments and unique challenges. The staff at Alta Air Logistics is a team of dedicated experts, who listen to the shipping needs of its customers.

Benjamin Ortez joined Alta Air Logistics a year ago, and has worked three years in the field of air freight while attending school. Ortez has a Bachelor of Justice degree from the University of Alaska Anchorage. After hours, Ortez runs a mobile DJ service with his partners, catering to any event, and teaching a variety of dance, from Latin to ballroom.


SUSAN CRANE

Benjamin Ortez, Operations Agent

—MARTI REEVE

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

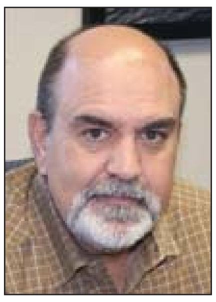
All of the companies listed above advertise on a regular basis with Petroleum News

Oil Patch Bits

Crowley announces organizational changes

Crowley said July 10 that management changes within its logistics services group have been made to improve organizational effectiveness and enhance the company's customer centric philosophy.


ROBERT WEIST


CARLOS RICE

Robert Weist has been promoted to vice president of sales and will be responsible for all business development functions and North American transportation services, including trucking and rail. He remains domiciled in Jacksonville and reports to Steve Collar, senior vice president and general manager, logistics.

Carlos Rice has been named vice president of operations and supply chain management and will oversee all freight service, warehousing and logistics operations. "With Rice responsible for the entire supply chain, he will be able to concentrate on building infrastructure required to expand Crowley's logistics capabilities, and providing cost effective services where they are most needed by customers," said Collar. Rice will remain domiciled in Miami. For more information visit www.crowley.com.

Petroleum Club golf tournament hits a hole in one

The 2009 Petroleum Club of Anchorage golf tournament took place July 16-17 at the Moose Run and Anchorage golf courses. This year the tournament partnered with The First Tee of Alaska and featured a pro-golf auction at the kickoff party. The First Tee program provides young people of all backgrounds an opportunity to develop life enhancing values such as confidence, perseverance and judgment through golf and character development. The program has had more than 200 youth participants and has introduced the game of golf to 400-plus students via The First Tee national school program. The program introduces The First Tee's nine core values into a physical education curriculum in elementary schools using the game of golf as its platform. The auction featured Bryan Anderson, Brandon Dubinsky, Rich Lundahl, Rob Nelson, Scott Taylor and club champion Billy Bomar.

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.

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EXPLORERS

state to build tax credits and swap them for cash.

Priming the pump

State officials recognize that a big challenge for oil and gas explorers is the huge expense they must risk upfront before they ever produce the first barrel of oil, Galvin said. By allowing them to cash in tax credits with the state, the belief is it helps encourage exploration and investment.

Galvin said $193 million is an impressive figure.

"The number shows there's a lot of activity going on out there," he said.

A Department of Revenue press release said $19 million of last year's outlay was for credits under the Exploration Incentive Credits program, and $174 million was for capital investment credits under the ACES production tax system.

"In addition, hundreds of millions of dollars in ACES tax credits were taken by companies already producing oil and gas in Alaska who have made new additional investments," the department said. "These tax credits were used by the companies as offsets to their tax liabilities, and did not require payment from the state."

—WESLEY LOY

FINANCE & ECONOMY

IEA forecasts strong rebound in demand

Global oil demand will rebound 1.7 percent next year as recovery in developing countries helps counter a two-year drop in oil usage sparked by the global recession, the International Energy Agency said July 10.

The Paris-based agency predicted July 10 in its closely watched monthly survey that global oil demand will increase by 1.4 million barrels a day in 2010 to 85.2 million barrels a day.

The IEA said this "strong rebound" would be led by growth in countries outside the rich-world Organization for Economic Cooperation and Development, but added that OECD countries should also post "a modest recovery."

A rebound in oil demand next year would mark the end of two straight years of falling global oil demand, the first back-to-back yearly drop the world has seen since 1982-83. The IEA left its forecast for 2009 oil demand unchanged, and still expects it to drop 2.9 percent, following a 0.3 percent decline in 2008.

—THE ASSOCIATED PRESS

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REVENUE

600,000 barrels a day.

But as time goes by, the production forecast becomes more and more dependent on barrels termed "under development" or "under evaluation."

Oil under development includes projects that companies have sanctioned to go forward, Galvin said. They include Eni's Nikaitchuq field; expansion of Pioneer's Oooguruk field; Prudhoe Bay, Kuparuk River and Alpine satellite fields; BP's Liberty field; and ExxonMobil's Point Thomson field.

Rising oil field costs have a negative impact on the state's production tax collections, and those costs have increased in the last three years, Galvin said.

Thoughts on oil prices

Some market watchers expect oil prices in coming years will go "up, up, up" to beyond $80 a barrel, Galvin said.

But the state isn't banking on that, he said.

"The last few months have shown how quickly conventional wisdom can be turned on its head," he said, referring to the plunge in oil prices following record highs approaching $140 a barrel in 2008.

The state's latest revenue forecast, issued in April, forecasts an average Alaska North Slope crude price for the current budget year of $58.29 a barrel, rising to $95.04 in 2018. These are West Coast spot prices. ANS crude settled at $61.54 on July 15.

How oil prices will behave in the future, of course, is anybody's guess, especially considering the global recession.

"We are at a sort of particularly unsure time in terms of where the markets go from here," Galvin said. ●

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LAWSUIT

investigations by state and federal agencies, and ultimately led to BPXA's conviction for criminal negligence under the Clean Water Act."

The remarks are contained in a 49-page argument opposing BP's May 26 motion to dismiss much of the state's lawsuit against BP.

The state sued the oil company, which operates the Prudhoe Bay field, on March 31. The civil suit seeks fines and punitive damages plus back taxes to compensate the state for a production shortfall of at least 35 million barrels of oil caused by two spills in 2006 and the ensuing work to repair or replace leaky, corroded pipelines.

BP's lawyers, in their May 26 motion, argue the state is "overreaching" with an improper lawsuit.

But state lawyers contend BP's arguments lack merit and "all of the state's claims must be allowed to go forward."

High stakes

The conflict between the state and BP has potential as a long and costly war.

Certainly the stakes are high. Steve Mulder, a chief assistant attorney general in the Alaska Department of Law's environmental section, has said the state is seeking back taxes and other collections that could tally as much as $1 billion.

BP already has felt considerable sting from the 2006 spills and the pipeline corrosion scandal, drawing criticism not only from regulators but from members of Congress for lax maintenance of key pipelines in Prudhoe, the nation's largest oil field. After pleading guilty in late 2007 to the federal pollution misdemeanor, a judge put the company's Alaska subsidiary on probation for three years and ordered more than $20 million in penalties.

The state wants a jury trial. To help with the case, it has hired an outside law firm, K&L Gates. The firm's Louisiana Cutler is working with Mulder.

Lawyers on both sides agree the case is highly complex. To help manage it, Superior Court Judge Peter Michalski of Anchorage has appointed a "discovery master" to referee trial preparations. Dan Hensley will make $300 an hour for the job.

Just when the case will come to trial is unclear.

A written summary of a recent conference before Judge Michalski says lawyers agree the trial "probably won't be ready in a year." The summary indicates the two sides have "attempted some form of settlement already."

Legal arguments

For now, the issue is whether BP will succeed in getting of the state's key claims thrown out.

BP's lawyers argue the state is improperly pursuing "tort claims" when it has powers to discourage oil spills and punish offenders under oil and gas leases and unit agreements — what amount to contracts. A tort generally is defined as a wrongful act, not including a breach of contract, that causes injury.

BP also argues the state shouldn't be allowed to collect punitive damages.

And it asks the judge to shift certain state claims — those concerning how much oil "waste" resulted from the spills and production shut-ins — to the AOGCC.

"Waste of oil is a highly technical subject, better suited for initial resolution by the AOGCC than by a lay jury," BP's lawyers wrote in their May 26 motion.

State attorneys urge the judge to reject BP's arguments.

"BPXA argues unpersuasively … that the oil and gas leases and unit agreements, which are contracts between it and the state, preclude the state from asserting tort claims against BPXA when the tort claims and breach of contract claims are based upon the same conduct," the state lawyers write. "Alaska law is clear that the state may bring both contract and tort claims in this lawsuit and BPXA's attempt to eliminate its tort liability must be rejected."

As for punitive damages, the state's lawyers write:

"BPXA essentially asks the court to take the radical step of making the state a second class citizen compared to any other plaintiff who sues for this kind of injury, and impose a limit on the state's potentially recoverable damages that would be inapplicable to any other party."

The state's lawyers concede, however, that the Alaska Supreme Court "has not had occasion to expressly address" the question of whether the state has the same right as a private plaintiff to obtain punitive damages.

The AOGCC angle

State lawyers urge the judge not to grant "BPXA's attempt to sideline this case while AOGCC considers a fraction of it."

A big part of the agency's job is ensuring companies don't waste or strand oil and gas as they produce the state's resources.

But sending part of the state's lawsuit against BP to the AOGCC to investigate whether waste occurred — an "enormous task" — would only succeed in wasting a lot of time in concluding the case, the state's lawyers argue.

Even if the agency concludes waste occurred, the court still will have to deal with the overlapping and equally technical question of how the production shortfall affected state revenue, the state's lawyers argue.

Anyway, if the three AOGCC commissioners had wanted to investigate the highly publicized 2006 spills, they surely could have, the lawyers add.

"Significantly, in the three years since the spills occurred and BPXA's inadequate corrosion control practices were revealed, the AOGCC has had plenty of time to exercise its discretion to initiate an investigation into whether waste has occurred and has not done so," the lawyers write.

The federal case

The same day the state sued BP, lawyers for the federal government filed a separate civil lawsuit against the company in U.S. District Court in Anchorage.

The federal suit is quite different from the state's in that it doesn't seek such collections as back taxes or punitive damages.

Rather, the federal case seeks fines for violation of water and air pollution laws with respect to the 2006 oil spills — the largest of which was 212,252 gallons covering two acres of tundra and the edge of a frozen lake — and the improper stripping of asbestos-containing material off insulated pipelines during inspection and repair operations.

The federal suit also seeks civil penalties against BP for violating pipeline safety laws by failing to comply with a corrective action order from the U.S. Pipeline and Hazardous Materials Safety Administration.

The potential financial liability to BP of the federal suit most likely is far less than that of the state lawsuit.

So far, the federal case hasn't progressed at all, with BP yet to file an answer to the government's complaint. ●

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OUTLOOK

ing up to 29 percent in the final quarter.

When CAODC released its revised forecast in February, it anticipated some price recovery in the second half of 2009, but Herring said that is "just not going" to happen.

The new target is based on average commodity prices for the year of $75 per barrel for West Texas Intermediate crude and C$5 per thousand cubic feet for natural gas.

The gutting of the service sector is affirmed by CAODC's new forecast of 78,455 operating days in 2009, down 17 percent from its February estimate of 95,000 and 40 percent from the 129,000 days expected when the initial forecast was released.

Herring said he expects some drilling contractors will idle parts of their fleet and others will either sell units or cut them apart.

Slump in new well permits

The gloomy outlook has ample supporting evidence.

New well permits issued by regulators slumped to 1,769 in the second quarter, down from 3,689 in the same period of 2008, while the first half count was 5,285 wells compared with 8,725 to the midpoint of 2008. Operators licensed only 33 wells outside Western Canada, including 28 in Ontario, three in Newfoundland and two in Quebec.

The hardest hit areas in the latest quarter were southwestern Saskatchewan (down 335 permits to 90), southeastern Alberta (down 293 to 479), east-central Alberta (down 268 to 190) and a Foothills zone in the Canadian Rockies (down 262 to 183).

The two areas that fared best were northeastern Alberta (down 58 wells to 164) and northern British Columbia (down 64 at 122). Operators in Western Canada licensed a total of 1,653 oil-targeted wells in the first half and 2,495 targeting gas.

The total of 2,097 licensed gas wells in Alberta was just under half the 4,103 wells in the same period last year. Mirroring the slump in gas prices, Saskatchewan issued 60 permits to the end of June compared with 595 last year and, despite the strong interest in British Columbia's Montney shale gas play that region saw permits drop to 338 from 448.

For all of Canada operators licensed 641 exploratory wells, or 14.65 percent of the total, down from 1,516 exploration wells accounting for 17.38 percent of all licenses in the first half of 2008.

Alberta land auctions down

Alberta continues to stumble at government land auctions, collecting a minuscule C$17.5 million in the first July sale, barely 10 percent of the comparable 2008 sale, raising the year-to-date total to C$115 million, compared with C$460 million a year earlier.

So far this year, land prices in Alberta have averaged C$136.64 per hectare (2.471 acres), a slump of 5.5 percent from the first half of 2008, while British Columbia, spurred on by interest in its Montney and Horn River areas, is averaging C$1,505.71, second only to last year's scorching C$3,535.15.

Gary Leach, executive director of the Small Explorers and Producers Association of Canada, said it "looks like we're on track for a pretty dismal year on the land front," indicating that "investment levels are going to stay low for some time to come."

He said the Alberta government can only rebuild confidence by taking a hard look at its regulatory and fiscal regime, including royalties and environmental approvals.

Alberta Treasury Board President Lloyd Snelgrove told an oil sands developers' conference in Calgary his government is attempting to reduce the regulatory burden facing the industry and is committed to "once again making Alberta the most competitive place" for investors and businesses. ●

continued from page 1

SATELLITES

north and east Swanson River satellites. In 2003 Unocal told the agency that Marathon would be the operator for the eastern satellite. At that time Unocal also requested that processing of its applications for the north satellite — Birch Hill — be suspended.

Marathon applied for a right of way to develop the east satellite in 2003. Coal, oil and natural gas resources in the east satellite have been conveyed to CIRI as part of its entitlement under the Alaska Native Claims Settlement Act with surface and remaining subsurface lands in the east satellite owned by the United States and managed by Fish and Wildlife.

Natural gas resources targeted at the north satellite — Birch Hill — are leased from the federal government. Surface lands at Birth Hill have been conveyed to the Tyonek Native Corp.

Chevron drilled Birch Hill

The Birch Hill Unit 22-25 well was drilled in 1965 by original unit operator Chevron — at that time called Standard Oil Company of California. Based on drilling results from the well the company proposed a 940-acre participating area in sections 23, 24, 25, 26 and 36 of township 9 north, range 9 west, Seward Meridian. The well was tested from perforations from 8,190 feet to 8,220 feet, producing an open flow potential of 17.5 million cubic feet a day and a stabilized flow rate of 6.2 million cubic feet per day of dry gas.

The state certified the BHU 22-25 well as capable of producing in paying quantities.

Chevron told the U.S. Geological Survey at the time that the Birch Hill "gas accumulation is controlled by faulting on the western and southern flanks and by a gas-water contact on the northern and eastern flanks." The well penetrated the pay sand from 8,190 feet to 8,222 feet. "The entire interval was gas productive with no gas-water contact present."

Drilling continued to 15,500 feet and the well was then plugged back to 8,810 feet and completed through perforations from 8,190 feet to 8,220 feet.

At the time the well was drilled Birch Hill was owned 50-50 by Standard Oil Company of California and the Atlantic Refining Co. which merged with Richfield to become ARCO.

Birch Hill plans

In its 44th plan of development and operations for Birch Hill, covering Dec. 14, 2008, to Dec. 14, 2009, Chevron said that while no drilling or remedial work had been conducted in the previous, 43rd plan of development, the company had "continued its technical and risk assessment work as part of the phased diagnostics and remedial wellwork approach to tie Birch Hill 22-25 into production facilities."

The company said that on an ongoing basis it was focused on maintaining the well's mechanical integrity, and said it "believes additional work must be completed to safely move toward tying in the well," and said it "does not intend to disrupt or potentially disrupt the mechanical integrity of the Birch Hill 25-22 well without adequate location access and a detailed emergency response plan specific to the well."

Chevron said it plans to complete initial onsite well inspections during the 44th plan, and to conduct wireline-pressure diagnostics and flow test the Birch Hill 22-25 well during the 2009-10 winter season.

If the well is commercial, typing it into production facilities would most likely occur in 2010.

Permitting efforts, including surveying the preferred right of way for the gravel road identified in the EIS, were initiated under the 43rd plan of development, the company said. Subject to completion of permitting, vegetation clearing and road construction would occur in the fall-winter of 2009 and Birch Hill 22-25 well testing in the winter-spring of 2009-10.

Well planned at Sunrise

CIRI, the resource owner at the east Swanson River satellite, told legislators in June that Marathon has been evaluating the prospect at Sunrise for several years and has shot 2-D seismic survey.

Marathon spokeswoman Lee Warren told Petroleum News in a July 15 e-mail that the company is "continuing to progress our efforts at Sunrise" and is currently planning to drill a well this winter.

Fish and Wildlife said that if full development occurred at the east satellite potential facilities would include some 7.4 miles of new gravel access road, up to 9.7 miles of new buried pipelines and utilities and two pads totaling 6.75 acres.

Full-scale development of the north satellite, Birch Hill, would include some 3.4 miles of new gravel access roads, 5.3 miles of new buried pipelines and utilities and two drill pads totaling 5.5 acres.

The agency said that development of the satellite projects would also require use of some existing facilities, existing roads and existing or new pipelines within the Swanson River field.

—KRISTEN NELSON

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DRIFT RIVER

the pipeline also collecting oil from Pacific Energy's production facilities for the West McArthur River and Redoubt Shoal fields.

"CIPL plans to transport oil stored at facilities at Granite Point and Trading Bay and ship it through CIPL's 42-mile pipeline for direct delivery to tankers which will be berthed at its Christy Lee platform located near its Drift River Terminal," CIPL said in a July 13 statement. "This modified procedure is designed to bypass the tanks at the Drift River Terminal, and crude oil storage operations at the terminal will remain suspended."

New equipment

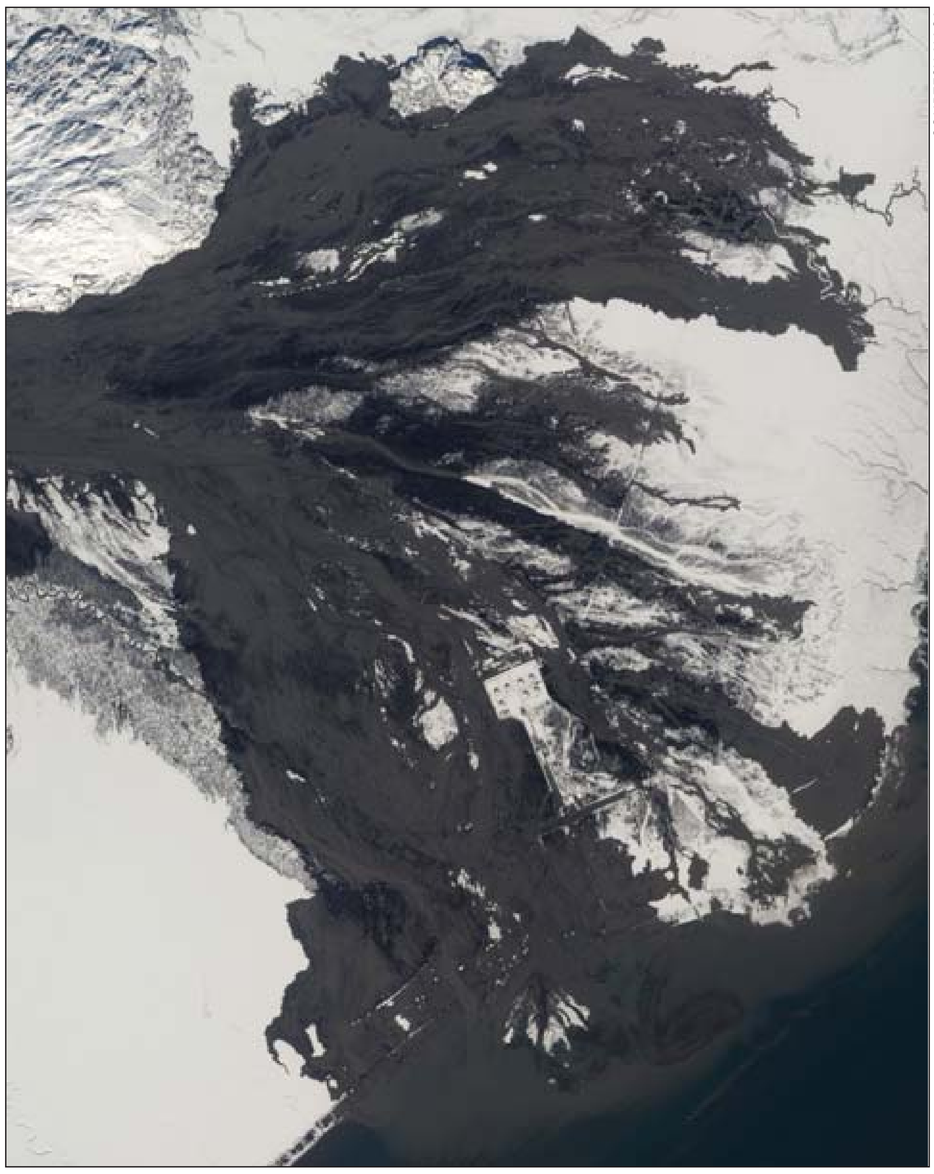
CIPL spokesman Santana Gonzalez told Petroleum News July 17 that CIPL is replacing pumps and metering systems at the terminal, as a result of which it will be possible to increase oil flow rates, to enable efficient transfer of oil direct to the tankers.

Startup of the modified procedure at the terminal depends on compliance with regulatory requirements, including an approved oil discharge prevention and contingency plan for the terminal — the Alaska Department of Environmental Conservation needs to determine whether any changes to that plan as a consequence of changes to the terminal procedures would impact CIPL's ability to respond to an oil spill, Betty Schorr, manager of the Division of Spill Prevention and Response's industry preparedness program, told Petroleum News July 17.

Schorr said that ADEC staff has met with CIPL and that ADEC is now waiting for CIPL's revised plan. Were ADEC to determine that the revised plan changes CIPL's oil spill response capability at the terminal, a 30-day public review period for the revised plan would be necessary, she said.

Chevron, operator of the west Cook Inlet oil fields that had to be shut-in at the beginning of April, says that it plans to resume field production once transportation of oil through Drift River restarts. However, the company must first offload about 90,000 barrels of oil currently stored at Granite Point and Trading Bay.

Offloading this oil will likely take about 28 hours, Gonzalez said.



COURTESY NASA

An April 4 NASA satellite photo of Drift River and the Drift River Marine Terminal, showing huge lahars, or volcanic mud flows, splaying out on either side of the terminal.

Field restart

Chevron says that it expects two shipments of oil per week from Drift River to be necessary, once the oil fields are back in production. However, company spokeswoman Roxanne Sinz told Petroleum News July 14 that it would not be possible to determine the impact of the oil field shut-in on continuing field production rates until the wells are restarted, a process that will be carried out well by well. The shut-in will likely have degraded well performance.

"We expect the production will be at a reduced rate," Sinz said.

Sinz said that Chevron had to furlough some contractors in April when the oil fields were shut-in, but that no Chevron employees had been laid off.

Modification of the facilities at Drift River to accommodate the new offloading arrangements and the subsequent restart of oil shipping and oil production are contingent on the Redoubt eruption not flaring back into life — the eruption started with multiple explosions on March 22.

Despite the buildup of a lava dome in the volcano after the early-April explosion, the Alaska Volcano Observatory in late June reported a decline in seismic activity, coupled with a slowdown in lava extrusion and gas emissions, all possibly signaling an end to the eruption. And AVO has lowered the volcano's alert level to "advisory."

The latest AVO reports indicate steam rising from the volcano, with seismic activity only just above background levels.

In March and early April, mud flows resulting from eruption-driven flooding of Drift River, adjacent the terminal, had lapped against the terminal tank farm's protective dike and encroached the facility's airstrip, causing CIPL to take the precautionary move of offloading oil from the terminal's active storage tanks into tankers, in two operations, under the guidance of a unified command that was formed to address the Drift River emergency. Following the second offloading operation, water was pumped into the tanks to act as ballast, to ensure that the tanks would not float from their foundations in the event of a flood inside the terminal site.

Remove ballast

According to a July 10 situation report issued by the Alaska Department of Environmental Conservation, the unified command has now approved plans to remove the ballast water and residual oil from the tanks in late July or early August, lest the freezing of the water during the winter threatens the tank integrity. The exact timing of the operation depends on the availability of a tanker to receive the oil and water that is pumped from the tanks.

And once the tanks are empty two tanks will be isolated from the piping system at the terminal by removing the appropriate connecting valves, with a third tank left on standby, for oil surge protection, the report says.

CIPL has not yet determined whether in the longer term to bring the Drift River storage tanks back into operation or to continue bypassing the tank farm, Gonzalez said. If the company elects not to use the tanks in the future it will clean out the two disconnected tanks in the summer of 2010, he said.

And according to the situation report the tank cleaning, "an intensive operation that requires cleaning crews and equipment to remain on site for an extended period of time," has been deferred to 2010 in case there is further eruptive activity at the volcano. ●

On the Web

See previous Petroleum News coverage:

"Where to from here?" in May 24, 2009, issue at www.petroleumnews.com/pnads/711680781.shtml

"CIPC shuts in Drift River terminal," in April 12, 2009, issue at www.petroleumnews.com/pnads/199817697.shtml

"Unified approach at Drift River Terminal," in April 05, 2009, issue at www.petroleumnews.com/pnads/764749181.shtml