Petroleum news

page 4 ANS production down 3% for April; Milne has largest increase

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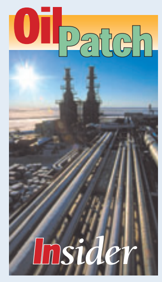
Hilcorp Alaska sign goes up; Oil Search lease approvals final



A HUGE HILCORP ALASKA SIGN is going up at the top of the JL Tower in midtown Anchorage as this issue of Petroleum News goes to press (see rendering in the print and pdf versions).

The 14-story JL Tower houses Hilcorp Alaska's headquarters. The company has about 50,000 square feet in the 300,000 square foot office building and has just added another 50,000 square feet of space, according to realtor Stewart Smith of SSS Commercial Real Estate (confirmed by Hilcorp source).

After Hilcorp's purchase of BP Exploration (Alaska)'s

see **INSIDER** page 11

Qatar orders 100 LNG tankers: $19B largest LNG ship order ever

Qatar Petroleum, QP, signed agreements June 1 with the "Big 3" Korean shipyards to reserve construction capacity through 2027 for 100 or more liquefied natural gas tankers, to fulfill its LNG carrier fleet requirements, the company said in a June 1 press release.

The deal, valued at 70 billion Qatari rials — $19.1 billion — represents approximately 60% of the global LNG shipbuilding capacity through 2027, according to Saad Sherida Al-Kaabi, minister of state for energy affairs and Qatar Petroleum president and CEO.

QP said the vessels are needed for support of ongoing expansion projects in Qatar's North Field and in the United States, and for long-term fleet replacement requirements.

see **TANKER ORDERS** page 11

Alberta strikes back, putting timelines on project approvals


JASON KENNEY

The Alberta government, under conservative leader Premier Jason Kenney, has shifted its focus from dealing with COVID-19 to rescuing its floundering economy.

At the forefront of its priorities is a sweeping frontal attack on barriers to fossil fuel development.

That coincides with a report by the Conference Board of Canada that Alberta's gross domestic product will shrink by a "historic" 6.8% this year, compared with a nation-

see **ALBERTA TIMELINES** page 9

US rig count continues tumble: 1944 was first count, 301 new low

Baker Hughes' weekly count of rotary rigs drilling in the U.S., issued since 1944, continues to drop, setting a new low of 301 for the week ending May 29, down 17 from the previous week and down 683 from a year ago.

Prior to this year, the low count by the Houston oilfield services company was 404 rigs in May 2016. That record has now been broken four weeks in a row: 374 rigs on May 8 of this year, 339 rigs on May 15; 318 on May 22; and this week's new low of 301.

The count has been dropping steadily: down by 17, 21, 35, 34, 64, 73, 62, 64, 44 and 20 rigs respectively, a total of 434, over the previous 10 weeks.

see **RIG COUNT** page 11

UTILITIES

Conditional approval

RCA says Chugach Electric can purchase ML&P if some changes made to deal

By ALAN BAILEY
For Petroleum News

The Regulatory Commission of Alaska has approved Chugach Electric Association's proposed purchase of Municipal Light & Power, to consolidate the two Anchorage based electric utilities, but requires changes and additions to the terms of the agreement between the parties involved in the deal. In a May 28 order the commission specified modified components of the deal that the parties would need to agree to, if the purchase is to close.

The general concept behind the ML&P acquisition is relatively simple: The idea is to gain efficiencies of scale and operational efficiencies by combining the two utilities into a single entity. But, given the differences between the manner in which the two utilities operate, and taking into account the need for fairness for existing utility customers

> *To maximize the benefits to ratepayers of the proposed consolidation of the two utilities and address the commission's concerns, the commission has added three new conditions that need to be met, for approval of the deal. …*

see **UTILITY SALE** page 8

FINANCE & ECONOMY

Breaking $40 a barrel oil

The only certainty in the oil market is its volatility; Eberhart predicts $70 by fall

By KAY CASHMAN
Petroleum News

On news that China's economy had rebounded to 90% of its pre-coronavirus levels and reports that OPEC+ would be meeting early to vote to continue production cuts for at least a month, Brent crude crept past $40 a barrel briefly on Wednesday, June 3. But by market close it had dropped to $39.79 with West Teas Intermediate at $37.29. Alaska North Slope crude's trading price, which is estimated by the Alaska Department of Revenue, was $39.70.

The reversal was blamed on doubts over the ability of the OPEC+ group to agree to extend output cuts and cancellation of its early June 4 meeting, as well as heightened worries about a build in U.S. fuel inventories.

Outlook improves

So, what have oil price forecasters been saying in the last few days?

Analysts at Fitch Solutions Country Risk and Industry Research have increased their forecast for the price of Brent crude oil in 2020, expecting it to average $40 per barrel this year, compared to their previous forecast of $33 per barrel.

Fitch Solutions sees Brent crude rising to $49 per barrel in 2021, a $7 per barrel increase compared to their previous projection.

Beyond that, Fitch Solutions analysts expect Brent will increase to $55 per barrel in 2022, $60

see **OIL MARKET** page 7

GOVERNMENT

Duplicate bonding solved?

AOGCC appears to be working with landowners that do initial surety bonding

By KAY CASHMAN
Petroleum News


SARA LONGAN

As several oil companies prepare for bonding level reconsideration hearings with the Alaska Oil and Gas Conservation Commission, the landowner that has been most critical of AOGCC's new higher bonding requirements, the Alaska Department of Natural Resources, has backed off, its confidence in the commission having increased in recent months.

"Since AOGCC implemented its new oil and gas surety bonding standards, DNR and AOGCC have successfully been working to increase our coordination, with a goal of ensuring all parties fully understand existing statewide bond coverage for the costs of Dismantlement, Removal, and Restoration (DR&R)," DNR Deputy Commissioner Sara Longan told Petroleum News in a June 1 email.

DNR is aware that some operators have "availed themselves of the flexibility available under 20AAC 25.025 (3) to request changes in AOGCC's bond requirements," she said, noting the regulation says: "upon request of an operator, or on its own motion, the commission may increase or decrease the amounts set out in (1) of this subsection based on evidence that engineering, geotechnical, environmental, or location conditions warrant an adjustment of those amounts."

see **DUPLICATE BONDING** page 9

● PIPELINES & DOWNSTREAM

Irving Oil aims higher

Reaches tentative deal to buy Newfoundland refinery, expanding international role by locking up control of sector in Atlantic Canada

By GARY PARK
For Petroleum News

Irving Oil, the privately held Canadian energy giant, is within reach of locking up control of Atlantic Canada's refining business along with adding a "building block" to its plans for ensuring an outlet for Western Canadian heavy crude.

For an unspecified amount, Irving now only needs Canadian government approval — expected within 60 days — to acquire Newfoundland's Come By Chance refinery, adding another dizzying chapter to that plant's history.

If the acquisition from New York-based investment firm Silverpeak proceeds, Irving will gain another 135,000 barrels per day of refining capacity on top of its existing 320,000 bpd plant at Saint John, New Brunswick, and 71,000 bpd refinery near Cork, Ireland.

The deal comes on the heels of Irving obtaining approval from the Canadian Transportation Agency for the company to source Western Canada crude through the Canadian government's Trans Mountain pipeline to Vancouver's tanker terminal.

The deal comes on the heels of Irving obtaining approval from the Canadian Transportation Agency for the company to source Western Canada crude through the Canadian government's Trans Mountain pipeline to Vancouver's tanker terminal. From there, foreign-owned, medium-sized tankers will sail down the Pacific Coast, through the Panama Canal and up to Atlantic Canada.

Irving said in a statement the refinery purchase is part of the company's broader plan to create energy security for its customers and Canada, as well as protecting 400 Newfoundland jobs.

As well as serving customers in its region, Irving hopes to serve buyers in the northeastern United States.

The company said the "two building blocks ... fit together with our existing strengths ... and our long-time objective of helping Canada be even more competitive in the international landscape," ending the refinery's reliance on feedstock from the United States, Saudi Arabia, Algeria, Nigeria and Norway.

Michael Ervin, vice president of petroleum consultant Kent Group, said the purchase is a "rational move by Irving" that will give the company more capacity and flexibility to extend its reach into New England markets.

"I think it's based on a long-term projection that many organizations hold ... that demand for gasoline is going to remain fairly robust over the long term," he told the Globe and Mail.

see IRVING OIL page 6

contents

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ON THE COVER

EXPLORATION & PRODUCTION

FINANCE & ECONOMY

PIPELINES & DOWNSTREAM

Alaska-Mackenzie Rig Report

The Alaska-Mackenzie Rig Report as of June 3, 2020.
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

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point, M-43	Hilcorp
Dreco 1000 UE	16 (SCR/TD)	Standby	
Dreco D2000 Uebd	19 (SCR/TD)	Standby	
AC Mobile	25	Standby	
OIME 2000	141 (SCR/TD)	Standby	
	142 (SCR/TD)	Standby	
TSM 700	Arctic Fox #1	Standby	
Hilcorp Alaska LLC			
Rotary Drilling	Innovation	Milne Point, I Pad	Hilcorp Alaska LLC
Kuukpik Drilling	5	Deadhorse	Available
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2 (CTD)	Deadhorse, Cold Stacked at Nabors Deadhorse Yard	BP
AC Coil	CDR-3 (CTD)	Kuparuk, Cold Stacked at 12 Acre Pad	ConocoPhillips
Ideco 900	3 (SCR/TD)	Deadhorse, Stacked	Available
Dreco 1000 UE	7-ES (SCR-TD)	Kuparuk, Cold Stacked	Oil Search
Mid-Continental U36A	3-S	Stacked	Available
Oilwell 700 E	4-ES (SCR)	Stacked	Available
Dreco 1000 UE	9-ES (SCR/TD)	Stacked	ConocoPhillips
Oilwell 2000 Hercules	14-E (SCR)	Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked	Brooks Range Petroleum
Oilwell 2000 Canrig 1050E	27-E (SCR-TD)	Stacked	Glacier Oil & Gas
Oilwell 2000	33-E	Deadhorse	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Stacked	Repsol
OIME 2000	245-E (SCR-ACTD)	12 Acre Pad, stacked	ENI
Academy AC electric CANRIG	105AC (AC-TD)	Stacked	Oil Search
Academy AC electric Heli-Rig	106AC (AC-TD)	Stacked	Great Bear Petroleum
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Deadhorse	Available
Superior 700 UE	2 (SCR/CTD)	Deadhorse, stacked	Available
Ideco 900	3 (SCR/TD)	Deadhorse, Stacked	Available
Rig Master 1500AC	4 (AC/TD)	Oliktok Point	ENI
Parker Drilling Arctic Operating LLC			
NOV ADS-10SD	272	Deadhorse, Stacked	Available
NOV ADS-10SD	273	Deadhorse, Stacked	Available

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Standby	
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk, Stacked	ENI

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BlueCrest Alaska Operating LLC			
Land Rig	BlueCrest Rig #1	Stacked	BlueCrest Alaska Operating LLC
Glacier Oil & Gas	Rig 37	West McArthur River Unit Workover	Glacier Oil & Gas
All American Oilfield LLC			
IDECO H-37	AAO 111	Stacked in the Peak yard	Available
Hilcorp Alaska LLC			
TSM-850	147	Stacked	Hilcorp Alaska LLC
TSM-850	169	Kenai Gas Field, well 42-12	Hilcorp Alaska LLC

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Hilcorp Alaska LLC			
National 110	C (TD)	Platform C, Stacked	Hilcorp Alaska LLC
	Rig 51	Steelhead Platform, Stacked	Hilcorp Alaska LLC
	Rig 56	Monopod A-13, stacked	Hilcorp Alaska LLC
Nordic Calista Services			
Land Rig	36 (TD)	Kenai, stacked	Available
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151, stacked at Rig Tenders where pre mobilization work is being performed	Hilcorp Alaska LLC
Furie Operating Alaska			
Randolf Yost jack-up		Nikiski, OSK dock	Available
Glacier Oil & Gas			
National 1320	35	Osprey Platform, activated	Glacier Oil & Gas

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	May 29	May 22	Year Ago
United States	301	318	984
Canada	20	21	85
Gulf of Mexico	12	12	23

Highest/Lowest

US/Highest	4530	December 1981
US/Lowest	301	May 2020

*Issued by Baker Hughes since 1944

● EXPLORATION & PRODUCTION

North Slope production for April down 3%

Average for month 498,422 bpd, down 14,498 bpd; largest volume drop at Prudhoe; largest volume increase at Hilcorp's Milne Point

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 498,422 barrels per day in April, 90% crude oil (448,849 bpd) and 10% natural gas liquids (49,573 bpd). This is a decrease of 2.8%, 14,498 bpd (7,475 bpd of crude and 7,022 bpd of NGLs) from a March average of 512,920 bpd (456,325 bpd of crude and 56,595 bpd of NLGs) and a drop of 3.3% from an April 2019 average of 515,292 bpd (460,075 bpd of crude and 55,216 bpd of NGLs.)

This production data is from the Alaska Oil and Gas Conservation Commission, which provides volumes by field and well on a month delay basis.

Alyeska Pipeline Service Co., operator of the trans-Alaska oil pipeline, began a proration on April 24 with a 10% cut to production. Data from the Alaska Department of Revenue's Tax Division show a dip in daily North Slope production beginning on April 24, with production dropping from more than 500,000 bpd most days in April to 476,758 bpd April 24, reaching 445,251 bpd on April 30. (The production cut increased to 15% on May 8, then dropped to 5% on May 15, and was ended May 21.) Alyeska prorates TAPS volumes based on factors including incoming flow rates, current and projected inventory and scheduled tanker movements, the company said in a May 21 press release announcing the end of the current proration.

Point Thomson, Milne up

Two North Slope fields, the Hilcorp Alaska operated Milne Point and the ExxonMobil Alaska Production operated Point Thomson field, showed substantial month-over-month production increases, while Badami, operated by Savant Alaska, a Glacier Oil & Gas company, and Endicott, operated by Hilcorp Alaska, were each up by smaller amounts.

Hilcorp Alaska took over as operator at Milne Point in 2014; BP remains a 50% working interest owner at the field, one of BP's Alaska assets which Hilcorp is in the process of acquiring.

In February Hilcorp said it was on track to double production at Milne, which averaged 18,400 bpd when the company took over as operator in November 2014.

In April, Milne Point averaged 32,794 bpd, up 7.1%, 2,170 bpd, from a March average of 30,624 bpd and up 29.8% from April 2019 when production averaged 25,260 bpd.

April production at Point Thomson averaged 9,278 bpd, up 22.1%, 1,677 bpd, from a March average of 7,601 bpd and up 15.6% from an April 2019 average of 8,027 bpd.

ExxonMobil has had compressor issues at the high-pressure field, resulting in wide production fluctuations. In its most recent plan of development it told the state it was addressing issues with its gas injection equipment, had begun installing upgraded components and expected to receive and install remaining equipment during the 2020-21 plan period.

As noted in the April 19 issue of Petroleum News, two compressor trains are now reported to be operating at the field, with an increase in condensate production expected from approximately 5,000 bpd to 10,000 bpd, the rated facility capacity at the field, with each of the two trains capable of 5,000-6,000 bpd.

Endicott averaged 7,543 bpd in April (6,569 bpd of crude, 87.1%, and 974 bpd of NGLs, 12.9%), up 117 bpd (all NGLs), a 1.6% increase, from a March average of 7,426 bpd (6,569 bpd of crude, 857 bpd of NGLs), and up 2.9% from an April 2019 average of 7,328 bpd (6,443 bpd of crude and 885 bpd of NGLs).

Badami averaged 1,308 bpd in April, up 4.5%, 56 bpd, from a March average of 1,252 bpd, but down 21.2% from an April 2019 average of 1,659 bpd.

Largest drop at Prudhoe

The BP Exploration (Alaska) operated Prudhoe Bay field, the Slope's largest, averaged 260,289 bpd in April (82.5% crude, 214,644 bpd, and 17.5% NGLs, 45,645 bpd), down 3.5%, 9,396 bpd (2,401 bpd of crude and 6,995 bpd of NGLs) from a March average of 269,686 bpd (217,045 bpd of crude and 52,641 bpd of NGLs), and down 4.6% from an April 2019 average of 272,748 bpd (221,280 bpd of crude and 51,469 bpd of NGLs).

In addition to the primary reservoir, production volumes from Prudhoe include Aurora, Borealis, Lisburne, Midnight Sun, Niakuk, Polaris, Point McIntyre, Put River, Raven and Schrader Bluff.

The ConocoPhillips Alaska-operated Kuparuk River field averaged 97,555 bpd in April, down 4.7%, 4,827 bpd, from a March average of 102,382 bpd, and down 2.8% from an April 2019 average of 100,342 bpd.

In addition to the main Kuparuk pool, the field produces from satellites at Meltwater, Tabasco and Tarn, and from West Sak.

Nikaitchuq, operated by Eni, averaged 17,737 bpd in April, down 1,218 bpd, 6.4%, from a March average of 18,956 bpd, but up 5.1% from an April 2019 average of 16,877 bpd.

Oooguruk, also operated by Eni, averaged 7,562 bpd in April, down 1,157 bpd, 13.3%, from a March average of 8,719 bpd, but up 13.8% from an April 2019 average of 6,645 bpd.

ConocoPhillips Alaska's Colville River averaged 50,854 bpd in April, down 892 bpd, 1.7%, from a March average of 51,747 bpd, and down 3.4% from an April 2019 average of 52,661 bpd.

In addition to oil from the main Alpine pool, Colville production includes satellite production from Fiord, Nanuq and Qannik.

ConocoPhillips Alaska's Greater Mooses Tooth in the National Petroleum Reserve-Alaska averaged 4,699 bpd in April, down 4%, 194 bpd, from a March average of 4,892 bpd and down 61.7% from an April 2019 average of 12,253 bpd. The field is producing from three wells with one, MT6-05, accounting for 74% of the field's production, 3,470 bpd in April.

The Hilcorp Alaska operated Northstar field averaged 9,492 bpd in April, down 145 bpd, 1.5%, from a March average of 9,636 bpd and down 16.5% from an April 2019 average of 11,373 bpd. In April 68.9% of the field's production, 6,539 bpd, was from crude oil and 31.1%, 2,953 bpd, from NGLs.

Cook Inlet production up 5%

Cook Inlet production averaged 13,854 bpd in April, up 4.7%, 626 bpd, from a March average of 13,228 bpd but down

see **ANS OUTPUT** *page 5*

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continued from page 4

ANS OUTPUT

10% from an April 2019 average of 15,397 bpd.

Only three Cook Inlet fields, Redoubt Shoal, West McArthur River and Trading Bay, had month-over-month production increases.

The largest increase, 771 bpd, was at Redoubt Shoal, operated by Cook Inlet Energy, a Glacier Oil & Gas company. The field's average production in April, 1,676 bpd, was an 85.3% increase from an average of 904 bpd in March, and a 36.1% increase from an April 2019 average of 1,231 bpd.

West McArthur River, also operated by Cook Inlet Energy, averaged 374 bpd in April, up 120 bpd, 47.5%, from a March average of 254 bpd but down 35% from an April 2019 average of 575 bpd.

Hilcorp's Trading Bay field averaged 1,383 bpd in April, up 60 bpd, 4.5%, from a March average of 1,324 bpd, but down 14.3% from an April 2019 average of 1,615 bpd.

All other Cook Inlet fields had month-over-month production declines.

Hilcorp's McArthur River field, Cook Inlet's largest, averaged 3,928 bpd in April, down 147 bpd, 3.6%, from a March average of 4,075 bpd and down 20% from an April 2019 average of 4,912 bpd.

Hilcorp's Granite Point averaged 3,230 bpd in April, down 28 bpd, 0.9%, from a March average of 3,258 bpd but up 24.9% from an April 2019 average of 2,586 bpd.

Hilcorp's Middle Ground Shoal averaged 1,229 bpd in April, down 1.3%, 16 bpd, from a March average of 1,245 bpd and down 7% from an April 2019 average of 1,321 bpd.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 1,018 bpd in April, down 50 bpd, 4.7%, from a March average of 1,068 bpd and down 39% from an April 2019 average of 1,668 bpd.

Hilcorp's Swanson River field averaged 852 bpd in April, down 7.3%, 67 bpd, from a March average of 919 bpd and down 20.5% from an April 2019 average of 1,072 bpd.

Hilcorp's Beaver Creek averaged 163 bpd in April, down 9.4%, 17 bpd, from a March average of 180 bpd and down 60.9% from an April 2019 average of 417 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

Contact Kristen Nelson at knelson@petroleumnews.com

Cook Inlet gas production down 8%

Natural gas production in Alaska's Cook Inlet averaged 204,584 thousand cubic feet per day in April, down 8.4%, 8,934 mcf per day, from a March average of 211,619 mcf per day and down 11.2% from an April 2019 average of 230,255 mcf per day.

This data is from the Alaska Oil and Gas Conservation Commission, which reports production on a month-delay basis. For natural gas AOGCC reports measurements in thousands of cubic feet, mcf.

Volumes from the inlet's seven largest gas fields, which accounted for 81% of inlet gas production in April, averaged 165,400 mcf per day, down 4.5% from March, when they accounted for 82% of production.

Of those seven fields, only Hilcorp Alaska's McArthur River had a month-over-month increase, averaging 20,819 mcf per day, up 2.7%, 555 mcf per day, from a March average of 20,264 mcf per day, but down 11.9% from an April 2019 average of 23,618 mcf per day.

The other six had month-over-month production declines.

Hilcorp's Ninilchik field averaged 34,313 mcf per day in April, down 10%, 3,841 mcf per day, from a March average of 38,154 mcf per day and down 22.8% from an April 2019 average of 44,470 mcf per day.

Hilcorp's Kenai field averaged 33,368 mcf per day in April, down 2,592 mcf per day, 7.5%, from a March average of 36,060 mcf per day, but up 1.5% from an April 2019 average of 32,863 mcf per day.

Hilcorp's Swanson River averaged 32,067 mcf per day, down 0.6%, 198 mcf per day, from a March average of 32,265 mcf per day and down 5.7% from an April 2019 average of 33,988 mcf per day.

Beluga River, operated by Hilcorp, averaged 18,204 mcf per day in April, down 375 mcf per day, 2%, from a March average of 18,578 mcf per day and down 33% from an April 2019 average of 27,163 mcf per day.

Kitchen Lights, operated by Furie, averaged 13,790 mcf per day in April, down 1%, 137 mcf per day, from a March average of 13,927 mcf per day and up 18.9% from an April 2019 average of 11,597 mcf per day.

Hilcorp's North Cook Inlet averaged 12,839 mcf per day in April, down 8.4%, 1,184 mcf per day, from a March average of 14,023 mcf per day and down 10.9% from an April 2019 average of 14,416 mcf per day.

Smaller inlet fields

Among smaller Cook Inlet fields, Hilcorp's Beaver Creek had a significant month-over-month gas production increase, averaging 9,145 mcf per day in April, up 1,899 mcf per day, a 26.2% increase from a March average of 7,246 mcf per day and also up 18.3% from an April 2019 average of 7,733 mcf per day. Other smaller fields also had increases, although not so large as that at Beaver Creek.

Hilcorp's Trading Bay averaged 3,121 mcf per day in April, up 6.9%, 201 mcf per day, from a March average of 2,920 mcf per day but down 4.8% from an April 2019 average of 3,278 mcf per day.

Hilcorp's Middle Ground Shoal averaged 357 mcf per day in April, up 34.9%, 92 mcf per day, from a March average of 265 mcf per day and up 55.8% from an April 2019 average of 229 mcf per day.

Hilcorp's Granite Point averaged 3,524 mcf per day in April, up 1.2%, 41 mcf per day, from a March average of 3,483 mcf per day and up 26.7% from an April 2019 average of 2,782 mcf per day.

Hilcorp's Lewis River averaged 1,105 mcf per day in April, up 1.4%, 15 mcf per day, from a March average of 1,090 mcf per day and up 346.7% from an April 2019 average of 247 mcf per day.

Redoubt Shoal, operated by Cook Inlet Energy, a Glacier Oil & Gas company, averaged 271 mcf per day in April, up 1.3%, 3 mcf per day, from a March average of 268 mcf per day and up 12.2% from an April 2019 average of 242 mcf per day.

Other smaller fields had decreases.

AIX's Kenai Loop averaged 5,230 mcf per day in April, down 0.2%, 10 mcf per day, from a March average of 5,241 mcf per day and down 2.9% from an April 2019 average of 5,387 mcf per day.

Hilcorp's Cannery Loop averaged 4,460 mcf per day in April, down 7.7%, 370 mcf per day, from a March average of 4,829 mcf per day but up 13.8% from an April 2019 average of 3,919 mcf per day.

Hilcorp's Deep Creek averaged 4,074 mcf per day in April, down 0.4%, 17 mcf per day, from a March average of 4,092 mcf per day and down 16.2% from an April 2019 average of 4,864 mcf per day.

The Cook Inlet Energy-operated North Fork field averaged 3,593 mcf per day in April, down 0.9%, 32 mcf per day, from a March average of 3,625 mcf per day and down 0.6% from an April 2019 average of 3,614 mcf per day.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 3,453 mcf per day in April, down 16.9%, 701 mcf per day, from a March average of 4,154 mcf per day and down 61% from an April 2019 average of 8,863 mcf per day.

Hilcorp's Ivan River averaged 346 mcf per day in April, down 4.3%, 16 mcf per day, from a March average of 362 mcf per day and down 26.3% from an April 2019 average of 470 mcf per day.

Amaroq's Nicolai Creek averaged 260 mcf per day in April, down 7.7%, 22 mcf per day, from a March average of 282 mcf per day and down 36% from an April 2019 average of 406 mcf per day.

Hilcorp's Nikolaevsk averaged 187 mcf per day in April, down 55.5%, 234 mcf per day, from a March average of 421 mcf per day; AOGCC records show no production from the field in April 2019.

Cook Inlet Energy's West McArthur River averaged 58 mcf per day in April, down 18.6%, 13 mcf per day, from a March average of 71 mcf per day and down 45.9% from an April 2019 average of 106 mcf per day.

Cook Inlet natural gas production peaked in the mid-1990s at more than 850,000 mcf per day.

—KRISTEN NELSON

● FINANCE & ECONOMY

Hex advances on Furie asset purchase

Loan document plan supplement filed, as June-end closing nears; closing under new ownership structure as HEX Cook Inlet LLC

By STEVE SUTHERLIN
Petroleum News

Anchorage based Hex LLC is moving forward — under a new name — with its planned purchase to acquire the assets and existing equity interests of Chapter 11 debtor Furie Operating Alaska LLC and related debtor companies — Cornucopia Oil & Gas Company LLC and Corsair Oil & Gas LLC.

The debtors filed a plan supplement on May 29 in the U.S. Bankruptcy Court for the District of Delaware, to the May 6 second amended joint plan of reorganization for the debtors.

The supplement — subject to the approval of all parties — includes loan documents for Hex's proposed Alaska Industrial Development and Export Authority purchase financing, a debtor in possession replacement loan agreement, a new tax credit loan agreement, and other documents.

The plan supplement documents have not yet been approved by the bankruptcy court but will become part of the plan of reorganization once the plan is approved.

The sale, which is scheduled to close at the end of June, will take place as a private sale foreclosure.

Hex has elected to complete the foreclosure sale through HEX Cook Inlet LLC, an Alaska limited liability company formed May 11, owned 80% by Hex and 20% by Rogue Wave AK LLC.

AIDEA loan

The initial AIDEA loan will be $7.5 million, with an option to borrow not more than $5 million as part of the AIDEA loan secured by a first priority lien in the collateral.

Hex must demonstrate to AIDEA that it has received capital contributions in an amount equal to at least $2.5 million, and Hex will pay an origination fee of 1% at closing.

The loan terms include an economic development clause; once Hex has achieved production of gas from the Sterling formation at sustained rates, it will "negotiate rates at a meaningful discount level to be reasonably determined between the parties to the agreement for interruptible gas volumes produced by the borrowers to underserved or constrained gas utilities in Alaska."

Payments are to be made quarterly based on a four-year amortization, subject to certain formulas including milestones of gas production from the field.

The loan is subject to a debt coverage ratio of 1.50:1.00 and a minimum reserve coverage ratio of 1.15:1.00 based on proved developed producing reserves — initially, Beluga A1-A3 wells, as adjusted to include Sterling wells, when producing.

On the effective date of the loan, on first day of each calendar quarter, the borrowers will make a mandatory prepayment of the loan, with accrued interest, in an amount equal to 100% of the borrowers' excess cash. The payment will be made by cash sweep from the proceeds account. Beginning on the first day of the calendar quarter after borrowers debottleneck the Beluga A4 well, and achieve a sustained gas production (as measured over a period of 30 days) exceeding 14.5 million standard cubic feet per day, and continuing on the first day of each calendar quarter, the borrowers will make a mandatory prepayment of the loan, with accrued interest, in an amount equal to 25% of the borrowers' excess cash. ●

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continued from page 2

IRVING OIL

"Irving clearly sees the Come By Chance refinery as a long-term player, even as some other refineries might close."

Ervin said the acquisition has gained value since a fire last summer forced Philadelphia Energy Solutions to permanently close the largest refinery on the Eastern seaboard.

Silverpeak spent C$400 million on improving the Come By Chance refinery's operations over the past few years, giving fresh hope to a facility that was built between 1970 and 1973 with Canadian and Newfoundland money.

The refinery went bankrupt in 1976 and lay idle until it was acquired by Petro-Canada in 1980 for C$10 million and, unable to turn a profit, was sold to the Canadian government for C$1. Since then the plant has passed through a succession of owners from Switzerland, South Korea, Canada and the United States. ●

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EXPLORATION & PRODUCTION

Glacier applies for operation suspensions

Glacier Oil and Gas Corp., parent company of Cook Inlet Energy and Savant Alaska, has applied to the Alaska Division of Oil and Gas for suspension of operations and production for its three oil fields in the state.

As previously reported by Petroleum News (see stories in May 24 issue), Glacier is shutting in production from Badami on the North Slope and Redoubt and West McArthur River in Cook Inlet.

In addition to these fields, the company operates the North Fork gas field on the Kenai Peninsula.

May 28 letters from Glacier VP of Operations David Pascal to the division requested a suspension from May 1 through July 15, 2021, for Badami, May 4 through April 30, 2021, for Redoubt and May 17 through April 30, 2021 for West McArthur River. Pascal said the suspension periods coincide with current plans of operations.

"The present global condition of low crude oil prices, combined with a lack of demand, obligates Glacier to act as a prudent operator and suspend operations until demand and market price have sufficiently recovered to justify the resumption of production operations," Pascal said. He said the company's intent is to re-start operations. During the term of the suspension of operations "a reduced complement of employees" would monitor the facilities in warm standby status.

At Badami, Pascal said, employees would remain onsite both to monitor the Badami facility and to operate the Badami Pipeline which delivers production from Point Thomson to Endicott. He said the private airstrip at Badami would be maintained for continued access.

Pascal said that if market conditions improve before the end of the suspension, Glacier would coordinate with the division for submission of updated plans of development.

The applications each include lists of activities required for suspension, including shutting in and freeze protecting producing wells as applicable.

At Badami, flowlines "will be evacuated, protected from freeze and corrosion as applicable."

At Redoubt, which produces from wells on the Osprey Platform, subsea pipelines from the platform will be "purged, cleaned and protected" along with pipelines at the onshore Kustatan Production Facility.

"Cross country pipelines will be purged, cleaned and protected" at the West McArthur River.

At all the facilities, at least portions of the camps will be kept open to house personnel.

—KRISTEN NELSON

continued from page 1

OIL MARKET

in 2023 and $63 in 2024.

Morgan Stanley raised its year-end Brent price forecast to $40 per barrel, crediting a faster balance in global oil demand and supply as countries relax coronavirus restrictions and major producers cut supply.

"We expect demand to rebound to about 97 million barrels per day by Q4 as economies come out of lockdown — a significant improvement although still down about 4 million bpd year-on-year," the bank said.

Morgan Stanley also sees supply declining by the end of the year in OPEC+ countries, which it expects will result in an oil market that is 4-6 million barrels per day undersupplied during fourth quarter and first quarter 2021.

The bank said, however, that the recent rebalancing was primarily supply rather than demand driven with the increase in crude prices squeezing refining margins even more and oil products inventories rising fast relative to crude oil stocks.

The bank maintained its long-term forecast for the global benchmark at $45 per bar, while raising its third quarter Brent crude forecast to $35 per barrel from $30, and fourth quarter to $40 a barrel from $35.

The Bloomberg Consensus for Brent sees it averaging $39 per barrel this year, $50 in 2021, $55 in 2022, $60 in 2023 and $64 in 2024.

V-shaped recovery?

"Looking at next week and beyond, it is not unreasonable to expect solid progress in terms of the price. If so, then the horrors of negative pricing seen in mid-April may be seen as some sort of turning point, after which recovery set in," Capital.com said June 2.

"Much is hanging on the ability of the

Dan Eberhart … told Markets Insider the U.S. oil market is headed for a "mini-supply shock" with U.S. oil prices braced to rise more than 90% to $70 a barrel by fall. … a prediction supported by the fact the U.S. oil rig count is falling at the fastest rate on record and that by mid-May U.S. production had dropped more than 10% to 11.5 million barrels a day.

OPEC-NOPEC alliance to maintain discipline in terms of output, and also on the likelihood or otherwise of a swift bounce-back by major economies — in the jargon, a V-shaped recovery rather than a more shallow L-shaped recovery. But if these factors do slot into place, then the outlook for oil prices is brighter than it has been for some time," predicted Capital.com, which is one of few contract for difference, or CFD, trading platforms fully compliant with the regulations laid out by the European Security and Markets Authority.

In closing, Dan Eberhart, chief executive of Canary Drilling Services, told Markets Insider late June 3 that the U.S. oil market is headed for a "mini-supply shock" with U.S. oil prices braced to rise more than 90% to $70 a barrel by fall.

"We are going to find out the U.S. producers have cut more production than they needed to so there is going to be a mini supply shock for the U.S. oil market," Eberhart said, a prediction supported by the fact the U.S. oil rig count is falling at the fastest rate on record and that by mid-May U.S. production had dropped more than 10% to 11.5 million barrels a day. By comparison, following the 2014 oil price crash, oil production only fell by 1.1 million barrels a day, and that took a year. ●

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continued from page 1

UTILITY SALE

and Municipality of Anchorage taxpayers, the details of the deal are complex. Moreover, rather than making a straightforward upfront payment for ML&P, Chugach Electric wants to spread some of the cost over an extended time period.

Complexity challenging

In its order, the commission commented that, while it supports the concept of merging the two utilities, the complexities of the proposed transaction have proven challenging to evaluate and rule on. The commission's hearing into the proposed transaction has continued for many months and has several times been extended. However, combining the utilities could lead to economies of scale in employment, the more efficient use of generation and transmission assets, more efficient inventory management, better planning of future electrical system developments, and an improved business environment resulting from consistent electricity rates, the order says.

"We are still reviewing the order and the conditions imposed by the RCA to determine whether they are acceptable to Chugach," said Chugach Electric CEO Lee Thibert in a May 29 press release, responding to the order. "Assuming they are, we look forward to moving toward closing and a smooth transition for existing Chugach members and the new members from the ML&P system."

"The decision clearly states that it is in the public interest for the sale to move forward. We are assessing the issues raised by the proposed conditions and will continue to work with Chugach and other partners to conclude what has been a monumental effort," said Anchorage Mayor Ethan Berkowitz. "I would like to thank all involved, especially ML&P, the negotiating teams and municipal employees, who've helped us reach this milestone."

Four components

In general terms, there were four major components to the deal that the RCA has reviewed: an upfront payment to close the purchase; payments in lieu of tax, or PILT, to the Municipality of Anchorage over a period of 50 years, as compensation to the municipality for the loss of tax revenue from ML&P as a municipality-owned entity; a commitment to purchase electricity from the Eklutna hydroelectric power facility from the municipality for 35 years; and an agreement to reserve for ratepayers in the ML&P's service area benefits associated with ML&P's part ownership of the Beluga River gas field in Cook Inlet. A significant complication arises from the fact that Chugach Electric and ML&P both own portions of the Beluga River field, and use gas from the field as fuel under different commercial parameters — the proposed purchase arrangements would maintain separate accounting for gas attributable to Chugach Electric's and ML&P's portions of the field ownership and its cost to ratepayers in the two utilities' current service areas.

The total cost to Chugach Electric of the purchase, including the deferred payments, would amount to around $972 million.

Acquisition premium

One stumbling block for the commission has been the fact that the total purchase price would be considerably higher than the book value of ML&P's assets, and that Chugach Electric wants to recover this "acquisition premium," the excess of cost over asset value, from the rates that it charges its customers. Under state law, a utility cannot recover an acquisition premium in this manner unless it can demonstrate that the benefits of the arrangement outweigh the costs.

In its order, the commission says that it will be satisfied that the proposed deal is in the public interest, provided that the terms of the deal are modified in the manner that the commission requires.

A further complication had arisen from an appeal over the prudence of ML&P's construction of its Plant 2A power generation facility and, hence, whether the value of that facility should be included in ML&P's book value. However, that appeal has been resolved, with Plant 2A remaining part of the valuation.

Adequate equity?

The commission is also concerned that the cost to Chugach Electric of purchasing ML&P will drain Chugach Electric's equity to a point that could weaken the utility's financial position, thus exposing its customers to unknown rate risks. In its order, the commission says that it may require an early rate case, should Chugach Electric's equity levels not rebound as quickly as planned, following the ML&P purchase. The commission is also concerned about uncertainty over Chugach Electric's future obligations relating to the management of the Beluga River field.

The commission strongly objects to the utilities' proposals to maintain different electricity rates for ratepayers in the current ML&P and Chugach Electric service areas for many years into the future, as part of the arrangements for PILT payments and for accounting for Beluga River field gas.

"One of the main goals of Anchorage electric utility consolidation should have been to eliminate Anchorage's electric rate bifurcation," the order says.

And, although as one of their parameters for the deal the two utilities had set an objective of no immediate change to customers' electricity rates, the commission says that, while the utility consolidation would likely have long-term benefits, rate increases in the short term may be necessary to ensure Chugach Electric's continued financial health. The commission order requires the approved deal not to commit to keeping electricity rates unchanged.

New conditions mandated

To maximize the benefits to ratepayers of the proposed consolidation of the two utilities and address the commission's concerns, the commission has added three new conditions that need to be met, for approval of the deal: the use of a single cost of power adjustment associated with the use of gas from the Beluga River field; the implementation of a single rate structure for all ratepayers in the consolidated utility, rather than the recovery of PILT costs only from customers in the current ML&P service area, as had been proposed; and a requirement that, prior to closing the deal, Chugach Electric and Matanuska Electric Association form an agreement for the implementation of security constrained merit order dispatch across their service areas.

That last condition relates to a long-term effort to achieve a more unified approach to the management and operation of the Alaska Railbelt electrical system. Economic dispatch involves the continuous use of the most efficient available power generation. Chugach Electric, ML&P and MEA had been working towards joint implementation of economic dispatch but put that initiative on hold in the light of the proposed purchase of ML&P by Chugach Electric.

To further protect Chugach Electric's financial health, the commission is also requiring the utility to file a rate case by the end of 2023, and to demonstrate an adequate equity level before any reduction in the utility's operating margins.

Major deal components approved

The commission is approving major components of the proposed deal, including the PILT payments and the payments for Eklutna power. However, the commission requires that Chugach Electric will compensate ML&P ratepayers for capital that they have contributed to the Beluga River field through their rates — compensation would take the form of a negative surcharge over a 10-year period. And the commission is approving a proposed transfer of $36 million from the Municipality of Anchorage to Chugach Electric to fund a rate reduction account for legacy ML&P customers over a period of three years.

The order says that, under a range of parameters for the future electricity market for the Chugach Electric and ML&P service areas, modeling indicates future financial benefits for electricity consumers if the ML&P purchase transaction proceeds.

To implement consistent rates across Chugach Electric's expanded service area, the utility will need to merge its existing certificate of public convenience and necessity with that of ML&P. The commission has agreed to a deadline of the end of 2023 to complete the consolidation of the expanded services under Chugach Electric's certificate. ML&P's existing certificate would be revoked. ●

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continued from page 1

ALBERTA TIMELINES

al decline of 4.3%, coming in the wake of COVID-19 shutdowns and a collapse of commodity prices.

Despite an economic contraction across Canada of 25% in the second quarter, the board expects a strong rebound in the second half of 2020, followed by growth of 6% in 2021.

Unemployment in Alberta is forecast to average more than 17% in the current quarter, reflecting a devastating nosedive in the petroleum industry, where companies have chopped C$12 billion from their 2019 spending.

Direct oil and gas employment has fallen by 13% in the past year to 169,000, with 7,700 jobs evaporating in April alone.

The outlook is so bad that the PetroLMI Division of Energy Safety Canada has dropped plans to issue a labor market outlook this spring, believing change is occurring so fast that it would be unable to deliver an accurate forecast.

Taking control of economic events

Tired of being stalled by opposition from British Columbia and Quebec and global governments, First Nations and environmentalists, the government has opted to shift its emphasis from dealing with COVID-19 to taking control of its own economic events.

The Kenney administration is also awaiting an initial report from its Economic Recovery Council (whose 12 members include former prime minister Stephen Harper) on ways to protect jobs during the economic crisis. Also pending is an updated budget, expected in August.

SONYA SAVAGE

Not content with just holding back, the government has suspended a wide array of environmental reporting procedures for oil sands companies; introduced legislation to set deadlines on approvals for energy projects; changed its coal policies to make it easier to develop open-pit coal mines in a sensitive section of the Rocky Mountains; and given Energy Minister Sonya Savage free rein to suggest this is a good time to build pipelines because pandemic public health restrictions limit protests against those projects.

The province has also passed legislation giving it the power to jail demonstrators for six months and/or imposing fines of up to C$25,000.

Seen as reaction to stalled megaprojects

The sum total of the aggressive moves is widely being interpreted by many friends and foes of the Kenney government as a lashing out at those who have stalled megaprojects to the point where some have either been abandoned or become bogged down in protests or legal challenges.

In a previously unannounced move, the Alberta Energy Regulator, a government agency, relieved companies of the responsibility to meet environmental monitoring conditions in their operating licenses.

Those procedures cover ground and surface water, most wildlife and bird monitoring and methane leaks, all of which the AER said risked exposing its officials to COVID-19.

Chief Allan Adam of the Athabasca Chipewyan First Nation said the decision destroyed 12 years of effort to negotiate the rules and will likely result in court action by First Nations.

Rachel Notley, leader of the Opposition New Democratic Party, said the decision was a "cynical and exploitive" use of the pandemic and would turn the Alberta industry's image into the "Wild West of environmental protection."

That view was reinforced when the British Broadcasting Corp. and The Guardian newspaper, outspoken opponents of oil sands development, both ridiculed a comment by Energy Minister Sonya Savage that protests against pipelines will be hindered by COVID-19 measures.

On the flip side, the Canadian Association of Petroleum Producers and Suncor Energy said they had pressed for an easing of the AER environmental regulations and tighter deadlines on project approvals.

Savage said the new legislation, while taking into account environmental concerns and public safety, will allow cabinet to set timelines and end an AER process that is "onerous, unpredictable and uncertain."

Changes to coal regulations

Separately, changes to Alberta's coal regulations, which were introduced in 1976 to protect the Rocky Mountains and Foothills, are forecast by Savage as a chance to create hundreds of jobs by "rescinding an outdated coal policy ... and (attracting) new investment."

Robin Campbell, president of the Canadian Coal Association, said he knew of at least six companies looking to establish mines in the Foothills region and export coal to Asia for use in steel production. He said each mine would likely employ 300 to 350 people.

Shaun Flucker, an environmental law professor at the University of Calgary, said that allowing open-pit development in the identified area would be "very destructive" to grizzly bears, caribou and other wild animals as well as rivers and other waterways, including the Athabasca River that flows to the Arctic Ocean.

Savage no longer low-key?

In her 15 months in the energy portfolio Savage has built a public reputation as low-key and thoughtful, reflecting her pre-government time dealing with legal and regulatory issues while employed by Enbridge and the Canadian Energy Pipeline Association.

With one swipe she shattered that carefully assembled career on an obscure industry podcast by suggesting "now is a great time" to be expanding the Trans Mountain pipeline "because (under COVID regulations) you can't have protests of more than 15 people."

"People are not going to have tolerance and patience for protests that get in the way of people working," she said.

Savage said "ideological protests" that get in the way of infrastructure development "are not going to be tolerated by ordinary Canadians."

Jason Nixon, leader of the government in the provincial legislature, said Savage "rightly pointed out (there are people in Alberta, across Canada and around the world) who have dedicated themselves to

see ALBERTA TIMELINES *page 11*

continued from page 1

DUPLICATE BONDING

Longan, who had led the department's battle with AOGCC's new bond requirements that several smaller and mid-sized oil companies said threatened their financial viability, told PN: "We at DNR recognize AOGCC's authority to follow this new regulatory process for adjusting its bonding levels, when requested or where appropriate. At the same time, we also appreciate that the enhanced coordination with AOGCC holds the promise of broader and more thorough understanding of the state's full range of DR&R bonding requirements.

"As AOGCC considers bonding levels for plugging and abandonment (P&A) costs, it is important that it continues to coordinate with other state agencies that also have bonding authorities. In the absence of effective state agency coordination, the state runs the risk of unnecessarily burdening operators with duplicative, or unnecessarily high costs. With such coordination, however, we can work together to achieve the state's important common goal of ensuring that those developing state hydrocarbon resources have surety bonds sufficient to properly cover DR&R costs, and ensure the resources can be produced safely and responsibly."

Constitutional mandate

While Alaska's Constitution mandates the development of the state's natural resources, including oil and gas, AOGCC appears to be the only state agency that does not consider the economic impact of its decisions on the ability of mineral rights lessees to explore for, develop and produce those deposits.

When asked for a comment on the new bonding levels, Commission Chair Jeremy Price refused: "At this time it would be premature to publicly discuss issues associated with the bonding regulation that went into effect last year. The AOGCC is still working through a number of reconsideration requests from operators."

Two of the three commissioners, Price and Jessie Chmielowski, did not serve on the commission when the new bonding regulations were being considered and public and agency comments were being gathered in 2018 and the first part of 2019.

Two of the three commissioners, Price and Jessie Chmielowski, did not serve on the commission when the new bonding regulations were being considered and public and agency comments were being gathered in 2018 and the first part of 2019.

Changes in bonding requirements

The AOGCC bonding requirements, formerly $100,000 for a single well and $200,000 for multiple wells, was raised last spring after a lengthy series of hearings, with the new amounts reflecting the commission's concern that companies would abandon wells, leaving the landowner, typically the state of Alaska, to pick up the cost for plugging and abandonment — a cost that would ultimately fall back on landowner DNR.

The commission notified companies with permitted wellheads last July, laying out the additional amounts required to bring bonding up to the new levels, which are based on the number of permitted wellheads: $400,000 per well for one to 10 wells; $6 million for 11-40 wells; $10 million for 41-100 wells; $20 million for 101-1,000 wells; and $30 million for more than 1,000 wells.

AOGCC received requests for reconsideration from several companies: AIX Energy, Alaskan Crude, Amaroq Resources, Cook Inlet Energy, Malamute Energy and Savant Alaska.

The commission issued its first ruling on a bonding reconsideration request in late March, reducing the bond required for four AIX Energy wells at the Kenai Loop field from $1.6 million to $200,000 based on the company having a $950,000 certificate of deposit in place for P&A with the landowner, Mental Health Trust Land Office. ●

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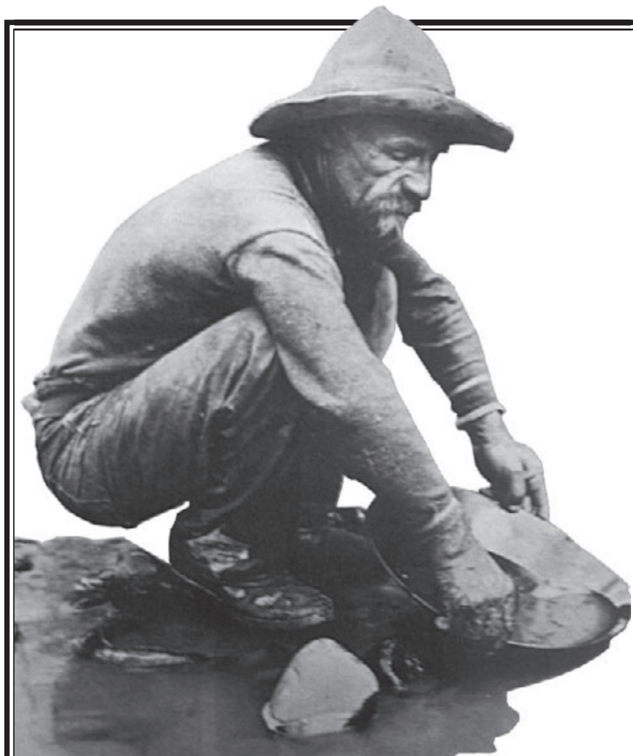

PAID MESSAGE TO GOV. DUNLEAVY & ALASKA LEGISLATORS FROM OILMAN JIM WHITE

THE TRUE BACKBONES OF ALASKA ARE THE ALASKA NATIVES, PRE-STATEHOOD RESIDENTS AND HOMESTEADERS THAT VOTED AND CREATED THIS GREAT STATE OF ALASKA. THEY ARE THE FORGOTTEN REAL HEROES OF ALASKA.

"RESULTS ALWAYS DEFINE INTENT"

Alaska has been a state the last 60+ years. Since Alaska became a state some 60 years ago, not one sole resident Alaskan has been able to explore or produce a single drop of oil or gas from his or her property. As a result, the immense wealth generated by Alaska's oil and gas has gone outside the state rather than staying in the hands of individual Alaskans.

Something is terribly wrong with this "result." So, let's try to get to the heart of how we got here and what we can do to change it.
After buying Alaska from Russia coaxing more citizens to come to the new territory of Alaska to homestead became a strategic necessity for the defense of the lower 48 states of America.

Following world war II, the US government desperately needed to have more new settlers to come, reside and settle in the new territory of Alaska to attempt to provide needed local civilian contract personnel in Alaska and produce fresh food and milk to service the thousands of soldiers and sailors who were being stationed in the territory of Alaska that were providing the 1st line of defense to protect the lower 48 states from any threats of any foreign nation.

Since Alaska's gold rush, the US had been trying to entice new citizens to come to the territory of Alaska. The US government promise to any new settler was that they could come pick a new homestead in the territory of Alaska. The US Interior Department rules were clearly understandable by any new Alaskan homesteader. If he or she lived on that homestead for two years and made certain improvements on the land, then they could keep the land and all the oil or gas that might be produced beneath it. That was how the Katalla Oil Field, Alaska's first oil field, was developed and was the enabling fact that allowed the Kennecott Copper mine to profitably produce and sell Alaska's copper for the next 30 years. To this day, this shallow oil field of wells less than 1000 feet deep is still owned by private citizens.

Many lower 48 citizens came up to the frigid new territory of Alaska to attempt to prove-up a new Alaskan homestead. These new folks soon found out living in the Alaskan brush was an arduous task that required some cash, but a whole lot of extreme physical work, extreme privation, and a lot of ingenuity just to prove up his new homestead and survive for the two year requirement. To be awarded a homestead they had to live in an area having few if any roads, few neighbors, a lot of big bears, and no electricity or running water. But they knew if they toughed it out, they would end up owning the land and everything below it to call their own.

This all changed when Swanson River Oil Field was discovered on the Kenai Peninsula in 1957. Suddenly there was a major push to stop any homesteader anywhere in Alaska from being able to own their oil and gas beneath their property. It took an act of congress to ensure that the pre-1957 homesteaders got to keep their oil and gas, but everyone else was out of luck. Those that homesteaded their property after 1957 did not even get to keep the gravel, much less the oil and gas beneath their land. The state government could clear the trees off their property and take the gravel if they needed it to build a road.

But the pre-1957 homesteaders were different; they owned the oil or gas beneath their lands **ONLY IF** they could get it to the surface and could cash in on it. The bottom line is this, if you cannot get the oil or gas beneath your property to the surface, you don't frickin own it.

In the 1970's the federal government only required a $10,000 bond to drill on federal lands. On homesteader's land, the state of Alaska in its infinite wisdom set a bonding requirement that was ten times higher. Before any homesteader could even think about drilling even a shallow oil or gas well on their own land they would have to come up with $100,000 cash bond. How many homesteaders do you know had an extra $100,000 laying around in 1970? It is important to note that there are thousands of oil and gas wells in the lower 48 that produce from less than a couple hundred feet below the surface.

But wait, it gets even better. The state of Alaska has now raised the homesteader's bonding requirement from $100,000 to $400,000! Even though the homesteader or their heirs technically own their oil and gas if they can get it to the surface, the high bonding requirements deprives them of their ability to get it to the surface where it can actually be sold and put into their bank account.

Another thing, the high $400,000 drilling bond cost is just another form of state-imposed taxation. Unfair taxation was the premise that caused the 1770-settlers of Boston to dump all its English tea into the Boston Harbor.

This is a double whammy! The land is already required by law to be pledged as collateral to pay all well plugging costs beneath his own homestead regardless, even if someone else had drilled the well. Even though there are only a couple of hundred of pre-1957 homesteaders, the state of Alaska bureaucrats who are pushing for higher bonding amounts are effectively throwing the homesteader who helped create this great state of Alaska under the bus.

The end result of these unreasonable excessive drilling bonds is that not one Alaskan resident has ever been able to produce or sell a single drop of Alaska's oil or gas since Alaska became a state some 60 years ago.

You might be thinking, "But what about the environment? If we let people drill on their own land, won't they trash it?" This land is their life. The homesteaders love their land more than anyone. They and their heirs know the tremendous sacrifice and effort they had to put in to get this land. It is preposterous to say they don't care about what happens to their land.

This writer believes that the current elected governmental officials are trying to do their best to restore equity back to the individual citizens of Alaska. We just need to make sure they do the right thing by lowering the bonding requirements so that individual Alaskans can be capable to rightfully explore for oil or gas on their own property.

Please again carefully remember, it is only when the oil or gas has come to the surface of the homestead can any homesteader be able to convert this produced oil and gas to cash-in-hand, and be deposited in the homesteader's own bank account.

The state should be compelled to disclose all its findings for these drastic measures penalizing and depriving pre-statehood homesteaders of the option to convert any or all of their oil and gas beneath their pre-statehood homestead to the homesteader's ownership.

-Jim White

continued from page 1

TANKER ORDERS

"We are moving full steam ahead with the North Field expansion projects to raise Qatar's LNG production capacity from 77 million today to 126 million tons per annum by 2027 to ensure the reliable supply of additional clean energy to the world at a time when investments to meet these requirements are most needed," Al-Kaabi said.

The CEOs and other executives of the shipyards — Daewoo Shipbuilding & Marine Engineering Co. Ltd, Hyundai Heavy Industries Holdings Co. Ltd and Samsung Heavy Industries Co. Ltd — joined Al-Kaabi in a virtual signing ceremony. The ceremony was also attended by senior representatives from Korea's Ministry of Trade, Industry & Energy, as well as executives from Qatar Petroleum and Qatargas.

Largest LNG tanker order ever placed

An LNG ship order of this size is unprecedented.

"With the conclusion of these milestone agreements, we have everything in place to commence the largest LNG shipbuilding program in history," Al-Kaabi said.

The ships are expected to feature state-of-the-art technology and environmentally friendly performance.

"The new LNG vessels will be equipped with the latest generation slow speed dual fuel engines, utilizing LNG as a fuel; this will ensure the most efficient performance and compliance with the latest global emission and environmental regulations," Al-Kaabi said. "We will continue working on reducing emissions from our fleet to protect the regional and global environment in line with the environmental objectives of the Qatar National Vision 2030."

The Korean order is in addition to an April agreement between Qatar Petroleum and Hudong-Zhonghua Shipbuilding Group Co. Ltd. — a wholly owned subsidiary of China State Shipbuilding Corporation Ltd — for a significant portion of Hudong's LNG ship construction capacity through 2027.

The size of the China deal may hinge on the ability of the Chinese to expand LNG shipbuilding capacity.

Al-Kaabi said the China agreement has the potential to be "well in excess of 11 billion Qatari rials, depending on our requirements and the extent of China's LNG shipbuilding capacity expansion."

Alaska may need Korean LNG ships too

Qilak LNG is looking to Korean shipyards to build ice breaking tankers to execute its plan to export LNG directly from a proposed facility offshore Point Thomson on the North Slope, to markets in Asia.

Depending on routes and contracts, the fleet for Alaska will likely number between four and 10 new ships, Qilak said in an October announcement.

Qilak proposes to use double acting LNG ships, with an efficient bow for open water and thin ice cover, and a heavy ice breaking stern, Qilak President and COO David Clarke told Petroleum News. The ship is run in reverse in heavy ice. The design has better open water performance than traditional ice breaking ships.

Similar vessels, designed in Finland and built in Korea, have been successfully employed to carry LNG from the Yamal LNG plant located in Sabetta on the Yamal Peninsula, in Arctic Russia, Clarke said.

—STEVE SUTHERLIN

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continued from page 1

RIG COUNT

The company said 222 rigs targeted oil, down 15 from the previous week and down 578 from a year ago, while 77 targeted gas, down two from the previous week and down 107 from a year ago. There were two miscellaneous rigs active, unchanged from the previous week and up by two from a year ago.

Twenty-three of the holes were directional, 271 were horizontal and seven were vertical.

Alaska count unchanged

Ohio (9) was up one rig from the previous week.

Rig counts were unchanged for Alaska (3), Colorado (6), Louisiana (35), Oklahoma (12), West Virginia (8) and Wyoming (2).

The rig count in Texas, which at 127 has the most active rigs in the country, was down by 11 from the previous week and down by 353 from a year ago.

New Mexico (61), North Dakota (12) and Pennsylvania (20) were each down by two rigs from the previous week.

California (4) was down by one rig.

Baker Hughes shows Alaska with three active rigs for the week ending May 29, down by four from a year ago.

The largest rig count drop by basin was in the Permian, which also has the most active rigs at 148. The Permian count was down 14 from the previous week and down 304 from a year ago.

Baker Hughes has issued weekly rig counts for the U.S. and Canada since 1944 and began issuing international rig counts in 1975.

The U.S. rig count peaked at 4,530 in 1981. This week's count of 301 is a new low, surpassing lows set in the previous three weeks. Prior to that the previous low was 404 rigs in May 2016.

—KRISTEN NELSON

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continued from page 9

ALBERTA TIMELINES

stopping Alberta's clean natural resources from being able to enter the market."

But Nixon insisted the Alberta government "would not prevent someone from legally protesting," and was "not pushing for automatic approvals," adding Alberta was only seeking to introduce a "review process that would ... make our province more competitive" against similar jurisdictions.

The United Conservative Party government argues Alberta's approval times are twice as long as those in Saskatchewan and four times longer than Texas.

Duane Bratt, a political scientist at Calgary's Mount Royal University, said Savage's comments were consistent with "everything" Kenney's government has been saying, while it fights with environmental groups and some investors by demonstrating a "very narrow interest."

—GARY PARK

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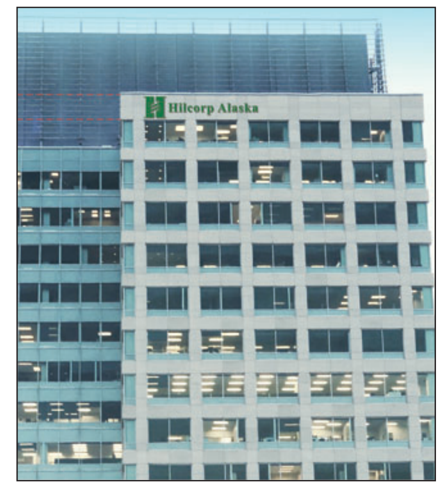
continued from page 1

INSIDER



COURTESY RENDERING

The sign on JL Tower was made and is being installed by Signco of Anchorage. The letters and Hilcorp logo measure 7 feet high by 54 feet long.

upstream and midstream assets closes, Hilcorp will continue to lease approximately 300,000 square feet in the 15-story BP Tower high rise in midtown Anchorage from the building's owner, Oak Street Real Estate Capital. (Oil Search also leases two stories in the building.)

When asked for confirmation, Luke Miller, manager, Alaska government and public affairs for Hilcorp Energy Co., told Petroleum News the following June 3: "Our current plan is to expand our Anchorage headquarters at the JL Tower in midtown Anchorage. We will not own the BP building after the transaction closes, as BP sold it a few years back. We will, however, inherit the lease. Culture is a critical component of our success as a company. Staying at our current location at the JL Tower ensures we are ready to take over operations on day one and is the right cultural fit for Hilcorp."

The sign on JL Tower was made and is being installed by Signco of Anchorage. The letters and Hilcorp logo measure 7 feet high by 54 feet long.

—KAY CASHMAN

Oil Search lease approvals final

THE WORKING INTEREST LEASE ownership transfers between Armstrong, GMT, Oil Search Alaska and Repsol that have recently appeared on the Alaska Department of Natural Resources' Division of Oil and Gas website are formal approvals by the state of Oil Search taking advantage of an option it closed last year.

"There should be more approvals in the next few weeks as the DNR processes the OSA/Repsol Alignment Agreement assignments. Note the effective dates of the assignments are last summer," Oil Search's manager of U.S. media and communications, Amy Burnett, told Petroleum News in a June 3 email in response to being asked to confirm what was behind the lease ownership transfers.

On June 27, 2019, Oil Search exercised its option to increase its stake in Pikka and Horseshoe leases west of the central North Slope, picking up the balance of Armstrong and GMT's working interest in the acreage. Operator Oil Search and partner Repsol are planning a Pikka development that will produce as much as 150,000 barrels per day.

The payout of the $450 million involved the buyout took place at the end of August.

In the June 27 closing, Oil Search and Repsol also aligned their interests across many of their shared North Slope assets, resulting in Oil Search retaining 51% in the Pikka unit and the Horseshoe block, while also purchasing a 51% interest in leases Repsol acquired in 2017, which are immediately east of Horseshoe within the prospective Nanushuk trend. That deal involved a net payment of $64.3 million from Repsol to Oil Search in the late August transaction.

As far as Oil Search's future relationship with Armstrong, Oil Search said in July 2019 that the two companies would continue to work together in reviewing opportunities on the North Slope, in accordance with the area of mutual interest agreement, or AMI, that was entered into as part of the original March 2018 acquisition of half of Armstrong's interest.

Oil Search and Armstrong are still partners in the eastern North Slope's Lagniappe lease block.

—KAY CASHMAN

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