Petroleum news

page 8 EIA: US crude to hit 10.7 million bpd this year, 11.8 million in '19

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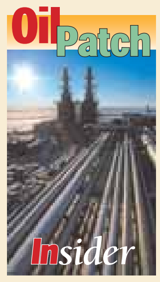
OGJ: North Slope black gold rush; BP's Dudley upbeat on o&g; See record-breaking polar flight video



OIL & GAS JOURNAL HAS JOINED national and international news sources in touting the revival of Alaska North Slope exploration, development and production.

Although in her Oct. 28 article, statistics editor Laura Bell gives a misleading number for monthly oil production — 380,000 barrels per day in July when all other 2018 months, including September, have been in the 475,000 to 540,000 bpd range, she was correct in saying the Slope was once a major source of oil production and reserves in the U.S.

see INSIDER page 12

Technology key to Prudhoe future 3-D survey, two new rigs planned

Some 40 years after the startup of the Prudhoe Bay oil field, field operator BP anticipates continuing its operations in Alaska for another 40 years, Fabian Wirnkar, BP vice president for reservoir development, told a meeting of the Commonwealth North Energy Action Coalition on Oct. 5. As the Prudhoe Bay field matures, the use of modern technology has become critical to extending field life and to maintaining the field's economic viability, Wirnkar said.

New seismic survey

As part of its commitment to Prudhoe Bay, BP is going to conduct a new 3-D seismic survey across the field during the coming winter. The company is also bringing in two new drilling rigs

see PRUDHOE TECHNOLOGY page 12

BlueCrest drills Cosmopolitan 'fish bone' multilateral wells

BlueCrest Alaska Operating LLC told the Alaska Department of Natural Resources, Division of Oil and Gas, in its fifth plan of development for the Cosmopolitan unit that it has begun drilling what it calls fish bone wells at the unit.

The multilateral design of these wells essentially does fracking as a function of well drilling, the company said.

The company drilled the first fish bone, the H12 well, this year, under its fourth plan of development covering the 2018 calendar year. The H12 consists of a wellbore with a long horizontal tail with seven vertical laterals rising up into the producing formation.

BlueCrest said with the fish bone well design it can more

see BLUECREST page 11

BRPC stays the course, looks for Mustang first oil in early 2019

Brooks Range Petroleum Corp. is moving closer to its goal of bringing the Mustang field into production by the first half of next year, according to a new plan of development.

The local operating arm of a multiparty joint venture expects to finish installing a temporary production facility at the onshore North Slope field by the second quarter of 2019, allowing oil production to begin from as many as three existing production wells while the company continues its efforts to install permanent infrastructure at the site.

The Mustang field is the first development at the Southern Miluveach unit, which is located in the fairway between the Kuparuk River unit and the Colville River unit. The company

see BRPC page 11

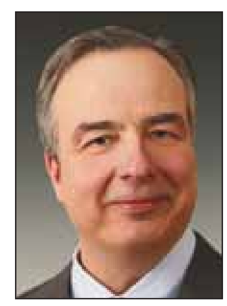
EXPLORATION & PRODUCTION

Early GMT-1 start

First oil begins to flow from ConocoPhillips' NPR-A Alpine satellite pad

By ALAN BAILEY
Petroleum News

ConocoPhillips has announced that oil production from its Greater Mooses Tooth 1 development started on Oct. 5, ahead of the anticipated schedule for the project — the company has previously said that it anticipated production beginning by the end of this year. ConocoPhillips has developed the GMT-1 well pad, located in the northeastern National Petroleum Reserve-Alaska, as a satellite of the Alpine oil field, connected to Alpine by a gravel road and pipeline via the CD-5 well pad.



JOE MARUSHACK

Up to 30,000 barrels per day

Production from GMT-1 is expected to peak at 25,000 to 30,000 barrels of oil per day from the upper Jurassic Alpine C sandstone. The development involves a combination of BLM, Arctic Slope Regional Corp. and Kuukpik land rights. Permitting for GMT-1 began in 2013, with the Bureau of Land Management issuing a permit to drill in October 2015. ConocoPhillips approved funding for the project in that same year, and construction began in 2017.

"This is another milestone for development in

see GMT-1 START page 11

UTILITIES

Tight pool delayed

Utilities tell RCA that they are pausing economic dispatch for ML&P sale

By ALAN BAILEY
Petroleum News

In an Oct. 5 letter to the Regulatory Commission of Alaska, Mark Johnson, general manager of Municipal Light & Power, and Lee Thibert, CEO of Chugach Electric Association, told the commission that they have decided to pause efforts to implement the economic dispatch of electrical power in Southcentral Alaska, pending the completion of work on the planned purchase of ML&P by Chugach Electric.

The managers said that it would be difficult to determine how the ML&P acquisition might impact the power pooling arrangements required for economic dispatch until the acquisition had been completed. The best path forward is to enable the limited resources available to the organizations to focus first on the acquisition deal, they said.

In January 2017 the three Southcentral utilities, Chugach Electric, ML&P and Matanuska Electric Association, signed a commitment to pool the operation of their generation and transmission assets over a 20-year period.

During an RCA meeting held on Oct. 10 to review the status of implementation of economic dispatch Mark Fouts, Chugach Electric executive manager for

see POWER POOLING page 10

PIPELINES & DOWNSTREAM

Pipeline talks rebooted

Trudeau government starts new round of Trans Mtn talks with indigenous communities

By GARY PARK
For Petroleum News

The Canadian government won't appeal a federal court decision that quashed its approval of the Trans Mountain pipeline expansion, opting instead to reopen negotiations with First Nations.

In the process it has insisted that those communities will not be able to block the project.

Natural Resources Minister Amarjeet Sohi said the government "understands that there might be groups that will still oppose this project" once the 22-week consultation period expires.

"That's fine; that's their right to do so," he said. "But that does not mean that if we fulfill our constitutional obligation to consult, that those groups may have (the power) of veto."

Notley noted that for now the oil industry and her government are losing millions of dollars a day from a shortage of pipeline capacity.

To put a stamp of credibility on the consultation process, the government hired former Supreme Court of Canada Justice Frank Iacobucci, known for his fairness, to oversee the discussions in concert with First Nations and Metis leaders.

Sohi said there is no "stop clock" on how long this new phase will take.

Squamish Nation Councilor Dustin Rivers Khelsilem said his community expects "an honor-

see PIPELINE TALKS page 9

● EXPLORATION & PRODUCTION

August ANS production up 9% from July

Average of 454,602 bpd up from 416,357 in July, when Colville down almost 3 weeks for planned maintenance; Cook Inlet holds steady

By KRISTEN NELSON

Petroleum News

Alaska North Slope crude oil and natural gas liquids production averaged 454,602 barrels per day in August, up 33,523 bpd, 9.2 percent, from a July average of 416,357 bpd and down 3.5 percent from 470,972 bpd in August 2017.

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

The largest month-over-month increase was at the ConocoPhillips Alaska-operated Colville River field, which was down for maintenance for almost three weeks in July and for the better part of two weeks in August, starting up Aug. 13 at 3,801 bpd.

The field averaged 41,565 bpd in August, compared to 24,013 bpd in July, an increase of 73.1 percent, 17,552 bpd, but still down substantially from June when it averaged 62,638. August production was down 37.7 percent from August 2017, when the field averaged 66,730 bpd.

The BP Exploration (Alaska)-operated Prudhoe Bay field averaged 234, 986 bpd (195,571 bpd of crude oil and 39,415 bpd of NGLs), up 4 percent, 8,966 bpd, from a July combined average of 226,020, and up 5.8 percent from an August 2017 combined average of 222,063 bpd.

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

The Hilcorp Alaska-operated Milne Point field averaged 22,172 bpd in August, up 27.8 percent, 4,826 bpd, from a July average of 17,346 bpd, and also up — by 9.3 percent — from an August 2017 average of 20,294 bpd.

The ConocoPhillips-operated Kuparuk River field averaged 109,407 bpd in August, up 7 percent, 7,133 bpd, from an average of 102,274 bpd in July, and also up, by 1.9 percent, from an August 2017 average of 107,377 bpd.

In addition to the main Kuparuk pool, Kuparuk volumes include production from satellites at Meltwater, Tabasco and Tarn, and from West Sak.

Prudhoe up 4 percent

The BP Exploration (Alaska)-operated Prudhoe Bay field averaged 234, 986 bpd (195,571 bpd of crude oil and 39,415 bpd of NGLs), up 4 percent, 8,966 bpd, from a July combined average of 226,020, and up 5.8 percent from an August 2017 combined average of 222,063 bpd.

Volumes shown for Prudhoe include: Aurora, Borealis, Lisburne, Midnight Sun, Niakuk, Polaris, Point McIntyre, Put River, Raven and Schrader Bluff.

The Hilcorp-operated Endicott field averaged 7,517 bpd (6,770 bpd of crude and 747 bpd of NGLs) in August, up 3.4 percent, 249 bpd, from a combined July

see ANS PRODUCTION *page 4*

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ON THE COVER

EXPLORATION & PRODUCTION

FINANCE & ECONOMY

NATURAL GAS

● EXPLORATION & PRODUCTION

Continuing Kitchen Lights development

Furie's new development plan anticipates a further development well in 2019; exploration drilling on hold over tax credit payments

By ALAN BAILEY
Petroleum News

Furie Operating Alaska's latest plan of development for its Cook Inlet Kitchen Lights gas field indicates that the company hopes to drill and evaluate an additional development well into the Sterling formation from the Julius R. production platform in 2019. According to the plan, which was filed with Alaska's Department of Natural Resources in early October, the company plans to log and test the well, but will not complete the well until after the results of the logging and testing have been evaluated — the company anticipates presenting a completion plan for the well to DNR.

Exploration financially constrained

Development of the Kitchen Lights field has taken place within the Corsair block of the Kitchen Lights unit. The plan of development says that Furie wants to continue exploration drilling within the unit, including the drilling of wells outside the Corsair block, but is currently limited by financial constraints.

"Exploration activities have been severely constrained by the state's lack of any meaningful payment for outstanding production tax credits for the last several years — and the absence of any payment for this fiscal year," the plan of development says.

However, Furie's technical team is in the process of developing a suite of options for exploration drilling, with that work anticipated to continue well into 2019. The plan of development says that, if additional financing becomes available, Furie will mature two prospects for exploration wells outside the Corsair block and present plans to DNR, indicating that "commercially reasonable efforts are underway to drill these wells either in 2019 or 2020."

Following fiscal problems resulting from the fall in the oil price in 2014, the state delayed payment of production tax credits that it owed to companies such as Furie. A bill introduced by Gov. Bill Walker and passed during the 2018 legislative session would have enabled the state to use bonding to pay money owed. However, this use of state bonding has been challenged in state court as unconstitutional — the court case has yet to be resolved.

> *The plan of development says that, if additional financing becomes available, Furie will mature two prospects for exploration wells outside the Corsair block and present plans to DNR, indicating that "commercially reasonable efforts are underway to drill these wells either in 2019 or 2020."*

This year's drilling

As previously reported in Petroleum News, during the 2019 drilling season Furie completed the KLU No. A-1 development well and drilled a new development well, the KLU No. A-4 well, in the Kitchen Lights field. The plan of development confirms that the A-4 well reached the Tyonek formation, below the Sterling and Beluga formations that currently produce gas from the field. Furie has characterized drilling into the Tyonek as an "exploration tail," designed to evaluate amplitude anomalies identified from seismic data. The drilling below the Sterling and Beluga went beyond Furie's drilling commitments for 2019 — the company is still evaluating the findings in the Tyonek, the plan of development says.

Furie is conducting its development drilling using the Spartan 151 jack-up rig, cantilevered over the Julius R. platform's drilling deck. The rig, which had been laid up in Seward for an extended period, underwent a commissioning process, including inspections by the American Bureau of Shipping and the U.S. Coast Guard, prior to this year's drilling operations. Furie can also install a workover rig on the platform, for well workovers.

Current production

The A-1 well, now completed, initially produced gas from the lower Sterling and subsequently produced gas from the upper Sterling. The well also penetrates down into the Beluga formation, but Furie does not anticipate completing the well in the Beluga until a later date.

The gas field produces from the Beluga formation in the KLU No. 3 and the KLU No. A-2A wells. Furie's plan of operations says that, as producing zones deplete, the company will re-complete or re-drill these wells to capture additional gas reserves in the Beluga and the Sterling. Well work conducted this year included adding new perforations in the Beluga in the No. 3 well and closing sleeves on some other perforations in that well, the plan of development says,

The plan of development says that reservoir sands in the Sterling and Beluga consist of braided fluvial sands, with varying levels of amalgamation and connectivity. Currently production is supported by the natural reservoir pressure. However, as each reservoir sand reaches its minimum pressure for gas depletion, Furie anticipates the implementation of compression, as appropriate, to increase gas recovery.

Focus on production wells

Furie's gas supply agreement with Enstar Natural Gas Co., the main gas utility in Southcentral Alaska, requires the operation of four production wells in the Kitchen Lights unit. Furie's plan says that the company is focusing on ongoing production from the No. 3, No. A-2A, No. A-1 and No. A-4 wells. Currently gas market conditions constrain the need for additional wells through 2019. However, in addition to the possibility of drilling one additional development well in 2019, the company does anticipate other development operations, including the addition of further perforations, in the No. A-2A and No. 3 wells, to boost production.

The Julius R. Platform has a total of six well slots, four of which are being used by the existing wells. Furie does not anticipate development drilling from surface locations beyond the platform, the plan of development says.

In addition to its drilling and well completion operations in 2018, Furie conducted maintenance operations on the Julius R. platform, carrying out work associated with generator replacement, adding sand monitors to well flowlines, replacing air compressors and upgrading crane alarm systems. The company also conducted a cathodic survey of the subsea pipeline that carries produced gas to onshore processing facilities, the plan of development says. ●

Contact Alan Bailey at abailey@petroleumnews.com

EXPLORATION & PRODUCTION

National drilling rig count down 2

The number of rigs drilling for oil and natural gas in the U.S. was down by two the week ending Oct. 5 to 1,052. At this time a year ago there were 936 active rigs.

Houston oilfield services company Baker Hughes reported that 861 rigs targeted oil (down two from the previous week) and 189 targeted natural gas (unchanged). Two were listed as miscellaneous (unchanged).

Among major oil- and gas-producing states, New Mexico and Oklahoma were each up two rigs; Pennsylvania was up one.

Texas was down five rigs; Alaska, Colorado and North Dakota were each down one.

The Baker Hughes rotary rig count shows five rigs active in Alaska, unchanged from a year ago.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

State announces upcoming well data release

The Alaska Department of Natural Resources, Division of Oil and Gas, published a list Oct. 1 of exploration well data and information that will be released and made available to the public within 30 days.

Two 2-D seismic data sets, both by PGS Onshore Inc., will be released: MLUP/NS 07-006-01 (Sagwon 2D) — an accompanying map shows three lines in Umiat Meridian, township 1 south to 3 north, ranges 5-14 east and MLUP/NS 06-001 (Rock Flour South 2D) — an accompanying map shows four lines in UM townships 6-10 north, ranges 9-13 east.

Well information to be released includes:

ConocoPhillips Alaska, Char 1, UM, section 17, T12N-R4E; Pioneer Natural Resources Alaska, Cronus 1, UM, 8-T8N-R6E; Anadarko Petroleum Corp., Gubik 3, UM, 17-T1N-R3E; Anadarko, Jacob's Ladder C, UM, 11-T8N-R17E; Savant Alaska LLC, Kupcake 1, UM, 29-T11N-R18E; BP Alaska Exploration Inc., Liviano 1, UM, 24-T13N-R9E; BP, Liviano 1A, UM, 24-T13N-R9E; Union Oil Company of California, Mastodon 6-3-9, UM, 6-T3N-R9E; Teck Cominco, North Basin 1, UM, 18-T31N-R18W; Teck, North Basin 2, UM, 17-T31N-R18W; Teck, North Basin 3, UM, 17-T31N-R18W; Teck, North Basin 4, UM, 17-T31N-R18W; Teck, North Basin 4A, UM, 17-T31N-R18W; Teck, North Basin 5, UM, 18-T31N-R18W; Union Oil, Panthera 28-6-9, UM, 28-T6N-R9E; Repsol E&P USA, Qugruk 1, UM, 28-T13N-R6E; Repsol, Qugruk 2, UM, 25-T13N-R5E; Repsol, Qugruk 3, UM, 6-T11N-R6E; Repsol, Qugruk 3A, UM, 6-T11N-R6E; Repsol, Qugruk 5, UM, 24-T12N-R6E; Repsol, Qugruk 5A, UM, 24-T12N-R6E; Savant, Badami Unit Red Wolf 2, UM, 36-T10N-R19E; Union Oil, Smilodon 9-4-9, UM, 9-T4N-R9E; Brooks Range Petroleum Corp., Tofkat 1, UM, 11-T10N-R5E; ConocoPhillips, Ugnu Production Test (1H-401), UM, 33-T12N-R10E.

The division said the following wells were being re-public noticed due to time elapsed:

Great Bear Petroleum, Alcor 1, UM, 5-T7N-R14E; Savant, Badami Unit B1-11A, UM 8-T9N-R20E; Savant, Badami Unit B1-38, UM, 9-T9N-R20E; Anadarko, Chandler 1, UM, 15-T1S-R2E; ConocoPhillips, Flat Top 1, UM, 16-T10N-R3E; Anadarko, Gubik 4, UM, 24-T1N-R3E; Repsol, Tuttu 1, UM, 8-T10N-R11E.

—PETROLEUM NEWS

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continued from page 2

ANS PRODUCTION

total of 7,268, and up 16.7 percent from an August 2017 combined total of 6,444 bod.

Northstar, also operated by Hilcorp, averaged 9,447 bpd in August (7,877 bpd of crude and 1,570 bpd of NGLs), up 1 percent from a July average of 9,351 bpd combined and up 17.3 percent from an August 2017 combined average of 8,055 bpd.

Production from the Caelus Alaska-operated Oooguruk field averaged 9,699 bpd, basically flat from July production of 9,696 bpd, but down 18.8 percent from August 2017 production of 11,948 bpd.

Badami down 8%

Badami, operated by Glacier Oil and Gas subsidiary Savant Alaska, averaged 1,708 bpd in August, down 8.3 percent, 154 bpd, from a July average of 1,862 bpd, but up 99.8 percent from an August 2017 average of 855 bpd.

Eni-operated Nikaitchuq averaged 17,933 bpd, down 2.8 percent, 521 bpd, from a July average of 18,454, and down 12.1 percent from an August 2017 average of 20,391 bpd.

Production from the ExxonMobil Production-operated Point Thomson field averaged 96 bpd in August, up 33.3 percent from a July average of 71 bpd, but down 98.6 percent from an August 2017 average of 6,814 bpd.

Point Thomson has basically been down due to compressor issues — it produced only one day in August and one day in July; in August 2017 the field produced for 11 days.

Cook Inlet

Cook Inlet production averaged 14,929 bpd in August, up 0.2 percent, 25 bpd, from a July average of 14,904, and up 1.6 percent from an August 2017 average of 14,700.

Hilcorp-operated McArthur River, Cook Inlet's largest field, averaged 4,984 bpd in August, up 4.6 percent, 219 bpd, from a July average of 4,765 but down 1.4 percent from an August 2017 average of 5,056 bpd.

Granite Point, also Hilcorp-operated, averaged 2,730 bpd in August, down 4.1 percent, 116 bpd, from a July average of 2,846, but up 17.6 percent from an August 2017 average of 2,322 bpd.

Hilcorp's Middle Ground Shoal averaged 1,555 bpd in August, up 27.6 percent, 336 bpd, from a July average of 1,219; the field had no production in August 2017.

Trading Bay, also operated by Hilcorp, averaged 1,417 bpd in August, down 8.8 percent, 137 bpd, from a July average of 1,554, and down 29.2 percent from an August 2017 average of 2,001 bpd.

Hilcorp's Swanson River averaged 1,335 bpd in August, up 3.5 percent, 45 bpd, from a July average of 1,290 bpd, but down 25.6 percent from an August 2017 average of 1,795 bpd.

Redoubt Shoal, operated by Glacier Oil and Gas, averaged 1,271 bpd in August, down 1.3 percent, 16 bpd, from a July average of 1,287, and down 27.7 percent from an August 2017 average of 1,759 bpd.

Glacier's West McArthur River averaged 882 bpd in August, down 11.3 percent, 112 bpd, from a July average of 994 bpd, and down 29.2 percent from an August 2017 average of 1,246 bpd.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 686 bpd in August, down 20.7 percent, 179 bpd, from a July average of 865, but up 99.4 percent from an August 2017 average of 344 bpd.

Hilcorp's Beaver Creek averaged 69 bpd in August, down 18.3 percent, 15 bpd, from a July average of 84 bpd, and down 96.8 percent from an August 2017 average of 177 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

● NATURAL GAS

BC premier in juggling act over LNG Canada

Must persuade Green Party, environmentalists, that project fits with goals to reduce carbon emissions; Greens won't vote to support

By GARY PARK
For Petroleum News

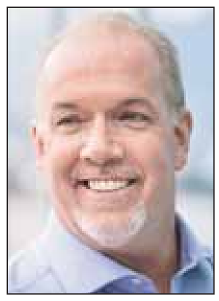
The British Columbia government has reacted with almost giddy delight to the formal launching of construction on the Shell-led LNG Canada project.

Premier John Horgan, who once ridiculed talk by former Premier Christy Clark of 20 LNG ventures in British Columbia, now ranks LNG Canada on the same historic scale as a "moon landing."

On the surface, the final investment decision by Shell and its four Asian partners opens the door to a windfall C$40 billion of capital spending, resulting in 10,000 construction jobs, even if thousands of them are filled by foreign workers being flown to the job site.

But Horgan is now faced with a challenge to persuade the Green Party and environmentalists that LNG Canada will not overturn his climate change pledges.

First, he has to reconcile carbon emissions from the project with British Columbia's legislated target for reducing the province's overall emissions to 40 percent below 2015 levels by 30 percent.



JOHN HORGAN

The test will come this fall when the government is supposed to release a revised climate plan to get the province 75 percent on the way to its target, allowing it to release a second-phase strategy in 2019 to eliminate the remaining 25 percent.

The overall plan will take into account the emissions associated with LNG Canada, estimated at 3.5 million metric tons a year or almost 10 percent of the total volume of emissions to be eliminated, if B.C. is to have any hope of lowering its emissions to 13 million metric tons a year by its eventual goal in 2050, given that releases from LNG Canada's most ambitious plans could be 8.6 million metric tons a year.

Green Party issues

For many, especially Andrew Weaver, leader of the B.C. Green Party and a climate-scientist-turned-politician, the government's goals are far-fetched and could only be achieved through vast sacrifices in other sectors of the economy.

The dilemma for Weaver is to choose between defending his party's very existence based on its insistence that the planet is in peril, while using the three legislators it has in the B.C. legislature to ensure the Horgan government remains in power.

Horgan believes he may have an answer by pondering ways to use cabinet orders to implement all of the taxes and relief for LNG Canada and avoiding a vote in the legislature that could topple his administration.

In March, his government promised LNG Canada tax breaks of C$5.3 billion, including exempting the project from planned increases in British Columbia's carbon tax and exempting construction from the provincial sales tax.

Weaver said the Greens will not vote to support the LNG sector, but hopes Horgan will achieve his objectives without any surprises and in good faith. ●

Contact Gary Park through publisher@petroleumnews.com

● FINANCE & ECONOMY

Alaska job losses have been slowing

ISER study assesses impact of oil price fluctuations on economies of Alaska and other oil states, and on employment levels

By ALAN BAILEY
Petroleum News

In a study into the impact of fluctuating oil prices on the economies of Alaska and other oil states, researchers from the University of Alaska Anchorage Institute of Social and Economic Research have found that the recession resulting from the downturn in oil prices in 2014 has lasted longer in Alaska and North Dakota than in other oil producing states such as Oklahoma, Louisiana and Wyoming. And it appears that, of the oil states, Alaska, Wyoming, Oklahoma and North Dakota are most dependent on the oil sector, a report from the ISER study says.

Following 34 months of negative economic growth in Alaska, the overall employment level in the state in June 2018 was at 96.6 percent of its level in June 2014, the report says. Unpacking this overall picture indicates that the oil and gas industry has been the hardest hit sector of the economy: Employment in this sector in June 2018 stood at 75.5 percent of its June 2014 size. Employment in the sector did increase in April and May of this year, but the June employment level proved lower that in June 2017.

By comparison, construction employment in June 2018 was 86.4 percent of the June 2014 level; business and professional services 91.6 percent; and retail 95 percent. Between July 2015 and July 2018 total job losses in the state amounted to 12,500, about 3.42 percent of the state's labor force.

An analysis of annual employment changes in the private sector shows that in the current Alaska recession the maximum year-on-year job loss recorded for June was 2.21 percent of the workforce and happened in 2016. The rate of loss has been slowing since then to 0.82 percent in June 2017 and 0.60 percent in June 2018.

The researchers also analyzed the mathematical relationship between the oil price and employment levels in oil states, finding that on average a 10 percent change in the oil price results in a 1.7 percent change in employment over periods of more than a year after an oil price shock. However, while Alaska, Louisiana and Oklahoma tend to respond symmetrically to both positive and negative shocks, North Dakota and Wyoming are more sensitive to negative shocks than to positive shocks. And the length of time taken for a state's economy to respond to a price shock tends to vary from one state to another.

The researchers reported that, while states like Alaska that have a strong dependence on the oil industry are unsurprisingly experiencing the longest and deepest recessions, the various indicators point to Alaska being in the tail end of its recession. The future of Alaska's economic development will depend on the success of the state's traditional economic sectors combined with the pursuit of new opportunities, and by ensuring that more of the economic value generated in the state remains in the state, the report says. ●

Contact Alan Bailey at abailey@petroleumnews.com

NATURAL GAS

AGDC counters MSB site comments to FERC

By KRISTEN NELSON
Petroleum News

The Alaska Gasline Development Corp. responded Oct. 2 to comments the Matanuska-Susitna Borough made to the Federal Energy Regulatory Commission on AGDC's environmental and engineering analysis of a site at Port MacKenzie which the borough identified in its January motion to intervene out-of-time.

The borough wants Port MacKenzie considered as an alternative to Nikiski for construction of the project's liquefied natural gas facility.

AGDC said FERC requested data that would allow its staff to quantitatively compare the Port MacKenzie alternative site with AGDC's proposed Nikiski site. FERC also requested documentation on recent consultations with the borough on the analysis.

AGDC said it provided the requested information July 13. AGDC said that when the borough commented on Sept. 14 it accused AGDC of providing "willfully misleading statements which reflect an inaccurate analysis of the options available at Port MacKenzie."

The borough said it had had "virtually no consultation" with AGDC.

AGDC said the borough's comments reflect "substantial consultation, including several meetings and exchanges of information," and said the borough's "incendiary accusations are baseless, entirely inappropriate and should be disregarded."

AGDC argues good faith

AGDC told FERC it "in good faith analyzed the Port MacKenzie site based on the information and recommendations provided to it by MSB" and the borough's consultant.

"MSB's proposed slight deviation in the location of one of the options analyzed by AGDC, identified by MSB at the eleventh hour, constitutes yet another moving target presented by MSB during these proceedings."

AGDC said the borough's latest proposal "does not materially change the results of the environmental and engineering analysis of alternatives performed by AGDC."

Substantial consultation

AGDC told FERC it met with the borough in person on four occasions between FERC's Feb. 15 data request and AGDC's July 13 response — in addition to exchanges of numerous emails and factual and technical information.

At an initial meeting in February AGDC said it noted areas of concern it had about Port MacKenzie and requested additional information and cited a letter in which the borough said it was pleased with the initial meeting and looked forward to further consultations.

There was a follow-up meeting in May at which the borough provided an update on Port MacKenzie activities and informed AGDC that Port MacKenzie "was close to finding funds to complete its $125 million Rail Spur Project, and timber sale shipments were picking up."

AGDC then identified two potential sites at Port MacKenzie, Option 1 and Option 2, chosen to fit the LNG facility design.

AGDC said it presented the borough with those options at a June 7 meeting, and told the borough there were "significant environmental, cost and operational concerns" at both options.

In a June 8 letter, the borough took issue with concerns AGDC had expressed over waterway congestion and operational concerns but agreed that there were "significant and major concerns" with the options, AGDC told FERC.

Master plan for port

AGDC said an issue of concern to it was other planned uses of Port MacKenzie, including the rail extension and timber contract.

At a June 19 meeting, AGDC said, the borough said the existing and planned port uses based on the master plan "could be altered or eliminated and AGDC should undertake its analysis based on a 'clean slate' without any consideration of other planned uses."

AGDC said it then analyzed Option 1 based on the premise that existing and proposed facilities could be removed from that area.

In a July 3 letter, AGDC told FERC, the borough "criticized Options 1 and 2 and contended that these options were intended by AGDC to ensure that the Nikiski site is chosen as the least environmentally damaging location. For the first time, MSB discussed an 'Option 3' which it later describes in its Comments as the 'Optimum Site'."

AGDC said that its July 13 response to FERC data requests was based on analysis of Option 1 and 2 alternatives, "and its consultations with MSB and relevant agencies." Option 1 was modified from the June 7 version to incorporate information the borough provided at the June 19 meeting, "as well as the 'clean slate' approach which assumed no other planned uses."

AGDC said that in the borough's August comments "it emphatically contends that its 'Option 3' or 'Optimum Site' is superior to the two options evaluated by AGDC. Moreover, MSB accuses AGDC of intentionally ignoring its preferred option and instead evaluating two options that it knew would maximize environmental impacts."

AGDC told FERC that although the borough said it proposed its optimum site several times over several years, the borough "does not produce any evidence of having proposed this location prior to its letter dated July 3, 2018, which is four years after the pre-filing review of this project was initiated, seven months after it intervened in this case, and after the four meetings with AGDC."

AGDC said FERC requested data that would allow its staff to quantitatively compare the Port MacKenzie alternative site with AGDC's proposed Nikiski site. FERC also requested documentation on recent consultations with the borough on the analysis.

The option was alluded to early in June and depicted with more detail July 3, AGDC said.

"MSB's identification of its Option 3, later self-proclaimed to be the 'Optimum Site', at this late date is a continuation of the moving target to which AGDC has had to respond with respect to MSB's proposals," AGDC told FERC.

Obstacle issue

AGDC told FERC that in addition to being proposed late in the process, the borough 'optimum site' option "does not avoid any of the obstacles and negative impacts associated with Option 1, as described by AGDC in its response to Data Request No. 20," and is "not materially different" than the Option 1 site evaluated by AGDC.

The 'optimum site' shifts Option 1 slightly north, AGDC said, but does not avoid most of the adverse impacts identified.

Some of the borough's responses "border on frivolous," AGDC said, citing the borough's contention that to make up for the longer transit time to Port MacKenzie, compared to Nikiski, LNG carriers could go faster — AGDC told FERC an additional LNG carrier would be needed.

AGDC said it "in good faith consulted with MSB and evaluated the two best options within the Port, consistent with the recommendations made by MSB and its own consultant." ●

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Royalty-in-kind purchase interest

The Alaska Department of Natural Resources published a solicitation of interest at the end of August for purchase of royalty-in-kind natural gas from the Prudhoe Bay and Point Thomson units.

In a Sept. 28 letter, Lieza Wilcox, vice president, commercial and economics for the Alaska Gasline Development Corp., told DNR that AGDC is interested in purchasing the state's RIK gas.

She said AGDC was in discussion with DNR on terms of the purchase, and "proposes to purchase the entire royalty in kind share of gas available from PBU and PTU for a major gas sale."

"AGDC would also purchase any PBU or PTU gas made available by DNR if tendered as tax-as-gas by the PBU and PTU leaseholders."

Under the tax-as-gas option the state would accept payment of taxes in molecules rather than in dollars.

Wilcox said the proposed purchase would begin during commissioning of the Alaska LNG System, include a build-up period and then 20 years of plateau purchase, followed by decline as production from the two fields declines, with the total duration estimated at 25-30 years.

AGDC would reserve a portion of the natural gas, up to 500 million cubic feet per day, to meet in-state needs, she said.

The gas would be delivered to AGDC at the unit boundaries and transported via pipeline to a gas treatment plant at Prudhoe Bay and would then enter a pipeline for delivery to in-state markets, or an LNG plant near Nikiski. Wilcox said gas not sold into in-state markets would be liquified and transported to other markets as LNG.

—KRISTEN NELSON

● FINANCE & ECONOMY

EIA: new US crude oil production records

2019 forecast 11.8 million bpd, up almost 300,000 bpd from September; gas to average 82.7 bcf this year, up 1.8 bcf from last month

By KRISTEN NELSON

Petroleum News

The U.S. Energy Information Administration said Oct. 10 in its October Short-Term Energy Outlook that U.S. crude oil production is estimated to have averaged 11.1 million barrels per day in September, up slightly from August, and is forecast to average 10.7 million bpd this year, up from 9.4 million bpd in 2017.

The forecast for 2019 is 11.8 million bpd, almost 300,000 bpd higher than the September forecast, reflecting higher production in July, which revised up the baseline of the forecast, and also reflecting higher forecast prices.

"The United States will set new records in crude oil production this year and in 2019, according to EIA's October forecast," EIA Administrator Dr. Linda Capuano said in a statement accompanying the forecast release. "The forecast for production in all of 2019 increased by about 2 percent from last month, due to production exceeding expectations in Texas and North Dakota this summer."

DR. LINDA CAPUANO

"OPEC members, along with Russia, increased crude oil production in the third quarter of 2018 and, in doing so, they were able to largely offset production decreases in Venezuela and Iran. OPEC spare capacity, on the other hand, has dropped to levels not seen in about two years," Capuano said.

Spot prices

Brent crude oil spot prices averaged $79 per barrel in September, EIA said, up $6 per barrel from August. The agency said it expects Brent to average $74 per barrel this year and $75 in 2019, with West Texas Intermediate expected to average about $6 lower than Brent in both years.

Brent is expected to average $81 per barrel in the fourth quarter of the year, $5 higher than forecast in September, EIA said. "This increase reflects recent price movements incorporated into EIA's forecast, the higher starting point for the forecast, and the possibility that crude oil prices could remain elevated while market participants assess how much crude oil production in Iran will decline in the coming months and the ability of other oil producers to offset lost volumes."

Iranian sanctions, reactions

EIA said both Brent and WTI reached four-year highs Oct. 3, with prices rising "in anticipation of potentially steep declines in Iranian crude oil production and exports as a result of the reinstitution of U.S. sanctions" beginning Nov. 4. EIA said the trade press is reporting that major oil-importing countries — including Japan, South Korea, China and India — are planning or considering sharp reductions in imports from Iran.

EIA said the amount of crude from Iran available in the global market may be much lower than expected in May when the U.S. said it would exit the Joint Comprehensive Plan of Action and it estimates that crude oil production in Iran has fallen by more than 400,000 bpd per day since May to an average of 3.4 million bpd in September.

Members of the Organization of the Petroleum Exporting Countries, along with Russia, agreed in June to increase oil production to the target set in November 2016, EIA said. In the third quarter OPEC — other than Iran and Venezuela — "increased crude oil production by more than the amount that crude oil production in Iran and Venezuela declined," EIA said.

The agency said recent price increases indicate concerns about the ability of Saudi Arabia, other OPEC members and Russia, to continue to offset further production declines in Iran and Venezuela.

The increases in OPEC production to offset the declines in Iran and Venezuela "have resulted in declining OPEC space crude oil production capacity," EIA said, estimating that OPEC spare capacity fell below 1.4 million bpd in September, "the lowest level since December 2016 when global oil inventory levels were much higher."

Concerns about declines and how much those declines can be offset have caused an increase in the fourth-quarter Brent forecast to $81 per barrel, up from $76 last month, EIA said.

But, despite declines in production from Iran and Venezuela, EIA said it "forecasts global oil supply and demand to be nearly balanced in 2019 contributing to downward oil price pressures."

Transportation constraints in the Permian basin are expected to be alleviated by the second half of 2019 and U.S. crude oil production, and potentially U.S. crude oil exports, are expected to increase, which could help keep oil prices in the mid-$70 per barrel range, EIA said.

Natural gas

U.S. dry natural gas production is estimated to have averaged 85.1 billion cubic feet per day in September, up 0.6 bcf from August, EIA said, with the 2018 average forecast at 82.7 bcf per day, up 7.9 bcf from 2017 "and establishing a new record high."

The 82.7 bcf per day estimate for 2018 is 1.8 bcf per day higher than the September forecast, EIA said, reflecting "higher than expected increases in Texas production in July, increasing the baseline of the forecast."

Natural gas production is expected to continue to rise in 2019 to an average of 87.7 bcf per day, up 3.1 bcf from the September forecast, with the 2019 upward revision "the result of increased expected production in the Haynesville region in response to higher forecast prices, upward revisions to the Permian region in response to higher prices, and expected new pipeline capacity to come online in the second quarter of 2019." ●

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PIPELINE TALKS

able consultation process that upholds our indigenous rights."

He said the government of Prime Minister Justin Trudeau "tried to ram (the Trans Mountain) project through our territory with a predetermined outcome and this was not acceptable to the Squamish Nation or the court."

Khelsilem said artificial timelines would not be acceptable to his community which faces the prospect of almost daily crude tankers sailing through its waters.

A spokesman for the Tsleil-Waututh Nation, that has a land claim covering the tanker terminal site, warned the Trudeau administration will end up back in court if it does not address his community's demands to kill or relocate the project.

Chief Michael LeBourdais, of the Whispering Pines Clinton Indian Band near Kamloops, in central British Columbia, said the new consultation is "extraordinarily ambitious."

Whispering Pines endorsed the pipeline and was the first to sign a benefits agreement on the pipeline, but LeBourdais said the consultation is an opportunity for all First Nations to push for improved benefits.

The appeal issue

Alberta Premier Rachel Notley was riled by the Trudeau government's refusal to challenge the Federal Court of Appeal ruling.

"We understand that pursuing an appeal is a longer-term path towards a solution," she said. "Nonetheless until that path succeeds ... their job is to keep all options open," she said.

Notley said a "tremendous amount of work" has already been done on the consultation front, so it should be possible to conclude the next round in "a fairly timely way."

She said Alberta wants to see construction resume next year "at some point. At this point we have to let the process play out."

Notley noted that for now the oil industry and her government are losing millions of dollars a day from a shortage of pipeline capacity.

Jason Kennedy, leader of Alberta's United Conservative Party, said Notley has failed to deliver on her promise to "hold Justin Trudeau's feet to the fire," including pushing for federal legislation to override the federal court.

Notley said the approval of the LNG Canada project in northern British Columbia suggests Alberta energy projects such as Trans Mountain are being held to a different standard.

"Albertans can be forgiven for being extremely frustrated with the way (the Canadian) federation is working right now because there is a high-level of jaw-dropping hypocrisy that is being demonstrated."

Chris Bloomer, chief executive officer of the Canadian Energy Pipeline Association, said the extra consultation will "not be a short process," despite the lack of pipeline capacity out of Alberta that has widened the gap between Brent crude and Western Canada Select prices to about US$40 a barrel.

Tim Pickering, chief investment officer with Auspice Capital, was unwilling to make any concessions to the Trudeau government, adding "I can't think of any other situation in life or in business where you put no timeline in place and it turns out well." ●

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Petroleum News Oil Patch Bits

Lynden continues humanitarian work in South Africa

Lynden International said Oct. 2 that in addition to handling critical samples for the Ebola vaccine in West Africa, it is also supporting the U.S. Agency for International Development by coordinating the transportation of HIV rapid test kits to Zambia.

Lynden International Business Development Director Dan Gotham has worked with the federal agency for many years and says Lynden is proud to provide a strong link in the global health supply chain. "In the past we've provided disaster assistance and rapid response with our Hercs and multiple transportation options," he said. Now, Lynden is supporting the test kit distribution as part of the President's Emergency Plan for AIDS Relief established in 2003 to address the global HIV/AIDS epidemic and help save the lives of those suffering from the disease, primarily in Africa.

Lynden coordinates the shipments of temperature-sensitive, high-value kits to South Africa. "We may have 30,000 kits in one 34-pallet shipment and 18,000 in another shipment of 55 pallets," explained Eric Klunder, senior account executive. "We recognize the significant health impacts of each shipment and use extreme care at every step of the process."

Lynden will handle the shipping through 2020 with destinations varying according to global health needs. "Besides delivering important cargo, we also serve as advisors to USAID," Klunder added. "We have experience in the global health field and in serving challenging areas with developing economies. Our specialty is coordinating diplomatic clearance within those countries."

Fluor joins with JGC on Canada LNG project

Fluor Corp. announced Oct. 2 that LNG Canada has made the final investment decision to build its liquefied natural gas export facility in Kitimat, British Columbia, Canada. Fluor's joint venture with JGC Corp. will provide the engineering, procurement, fabrication and construction on the project. Fluor will book its $8.4 billion share of the about $14 billion contract value in the fourth quarter of 2018.

"Fluor remains focused on delivering capital efficiency for our clients and we are excited that our joint venture team's innovative solutions have helped to enable LNG Canada to achieve final investment decision," said David Seaton, Fluor's chairman and chief executive officer. "We are committed to closely collaborating with LNG Canada and the local community to deliver this project safely and sustainably and to meet client needs."

The project scope will initially consist of two liquefaction units for a total of approximately 14 million tons per year of LNG. LNG Canada has the option to expand to four trains in the future.

More than 4,500 workers will be employed at the peak of construction. The joint venture will focus on hiring locally and then throughout British Columbia and Canada. Fluor and JGC will begin site activities this year, with first LNG expected around the middle of next decade.

LNG Canada is a joint venture comprised of Shell 40 percent, Petronas 25 percent, PetroChina 15 percent, Mitsubishi Corp. 15 percent and Kogas 5 percent.

Companies involved in Alaska's oil and gas industry

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

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POWER POOLING

fuel and corporate planning, told the commission that, assuming the ML&P purchase transaction closes in late 2019 (with board approval expected by the end of this year and the sale then going to the RCA for approval) it could be 2021 before economic dispatch is implemented. That takes into account the time taken to conduct utility integration activities following the close, the setting up of economic dispatch arrangements, and the need for an economic dispatch implementation period. Commissioner Antony Scott suggested that the pause could defer full implementation of economic dispatch until 2022.

Use of the most efficient generation

The Alaska Railbelt electrical system contains a variety of electrical generation facilities that have a wide range of generation efficiencies and are operated by several of the six Railbelt electricity utilities. The utilities try to minimize their cost of power by buying and selling power across the electrical grid from the more efficient generation units, under a protocol referred to as economy energy transactions. Merit ordered economic dispatch would take this process a step further by making continuous use of the cheapest available power though a unified power dispatch arrangement. The overall objective is to minimize the cost of electricity for consumers.

In 2015, following a directive from the state Legislature to conduct a study into the manner in which the Railbelt electrical system is operated, the RCA recommended a more unified approach to the management of the system, including the implementation of economic dispatch. Since then the commission has been encouraging voluntary efforts by the utilities to meet the commission's recommendations.

In January 2017 the three Southcentral utilities, Chugach Electric, ML&P and Matanuska Electric Association, signed a commitment to pool the operation of their generation and transmission assets over a 20-year period. The agreement involved a one-year period to form an agreement for the necessary processes and procedures.

In the event, given the complexities involved, the agreement took longer to formulate than originally anticipated. On June 13 of this year the three utilities told the commission that they anticipated finalizing the commercial agreement and the power dispatch procedures for the power pool by the end of September.

During the Oct. 10 RCA public meeting Fouts told the commissioners that the utilities had completed the commercial agreement for the power pool on June 30 and that since then the utilities' legal counsels had been polishing up the wording, in preparation for a commission filing. Other work required included the development of power dispatch procedures for the power pool, and the selection and acquisition of computer software to support the pooling arrangements.

Jeff Warner, strategic administrative coordinator for ML&P, said that he believed that the draft agreement completed in June was technically sound for moving forward with economic dispatch. To be finalized, it just needed regulatory and legal review, he said.

Proposed sale of ML&P

However, on April 3 the citizens of Anchorage voted to authorize the Municipality of Anchorage to proceed with a proposed sale of ML&P to Chugach Electric, Fouts said. Since then, two teams in Chugach Electric have been working on the two initiatives: the economic dispatch power pooling and the ML&P acquisition.

But the power pooling agreement includes language stating that, if there is a material change to generation ownership or capacity, the agreement would have to be reviewed and the benefits of the pooling would need to be re-assessed, Fouts said. With the acquisition of ML&P involving a material change of generation ownership, with unclear impacts on power pooling agreements, management determined that it would make best sense to first figure out and file the acquisition agreement, and then follow up with the filing of the power pooling agreement, he said.

The other issue that has arisen revolves around the practicalities of pushing through two major business reconfigurations in parallel, given the limited resources available within the utilities to execute the required changes. Fouts said that in July, during a review of how the economic dispatch arrangements would start, Chugach Electric staff who operate the utility's dispatch and control systems had questioned the feasibility of pushing both reconfigurations through at the same time.

Economy energy transactions

Ed Jenkin, director of power delivery for Matanuska Electric Association, reviewed the volumes of economy energy transactions on the Railbelt grid over the previous five months, commenting that, while not full economic dispatch, these transactions have significantly reduced the cost of power. The utilities say that they propose continuing their use and refinement of economy energy transactions, pending economic dispatch implementation.

Commissioner Scott questioned why, given that the integration of ML&P and Chugach Electric would appear to have features complementary to the pooling of power in economic dispatch, the two initiatives could not in fact be implemented in parallel. Moreover, Scott said, he understood that the economic dispatch agreement accommodated considerable flexibility with regard to generation ownership.

Disappointment expressed

Scott expressed his extreme disappointment with the pause in economic dispatch implementation.

"This was the low hanging fruit," Scott said. "I can't undersell how disappointed I am that this opportunity wasn't grasped and seized upon."

Tony Izzo, CEO and general manager of Matanuska Electric Association, said that he had opted not to sign the Oct. 5 letter to the commission. Izzo said he understood the complexities and workload involved in utility integration and, while supporting the decision over the economic dispatch delay, also felt disappointed. He wondered if something could have moved forward, perhaps even a two-party agreement conditional on approval of the ML&P sale.

"Although there may be tremendous uncertainty around ownership of assets, we stand ready to move forward with any party that is willing," Izzo said.

Commissioner Robert Pickett commented that the commission is going to send a letter to the state Legislature around the turn of the year, reviewing the status of electricity grid integration efforts, including the status of economic dispatch implementation. ●

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BLUECREST

efficiently drill to the outer reaches of the reservoir.

The H12 fish bone well is in production and BlueCrest said that based on evaluation of that well, the company decided to re-drill the H16 well in a similar fashion, with eight laterals. BlueCrest said in its Oct. 6 plan submittal that the H16 was scheduled to spud Oct. 7.

Fifth POD

The fifth plan of development covers the 2019 calendar year.

BlueCrest said it is submitting applications to drill another fish bone well at the beginning of the year. This new well, the H4, is expected to be some 3,200 feet south of existing wells and "will begin to test the southern extent of our reservoir." The H4, also in the fish bone design, will contain eight laterals.

After evaluating results of the H16a (the re-drill) and H4 fish bone wells, BlueCrest said it "will decide the best possible location for a possible second well in the 2019 drilling program. This well is currently anticipated to be the H11 Fish Bone Well that would step out to the north to evaluate the northern portion of the reservoir."

Cosmopolitan

The Cosmopolitan unit encompasses four state oil and gas leases off the coast of the Kenai Peninsula at Anchor Point. BlueCrest became operator in 2014 after holding a 75 percent interest since 2011 with Buccaneer Energy as operator.

Production from the field began in April 2016 from an exploration well with oil trucked to the Nikiski refinery from the field.

BlueCrest brought in a new rig to directionally drill extended reach wells from an onshore drill site, where field production facilities are located. That new powerful well began drilling in early 2017.

—KRISTEN NELSON

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BRPC

discovered the field in 2012, but a series of technical, economic and logistical complications led to years of delays and required alternative approaches to development.

To avoid losing the unit and its leases to expiration, BRPC successfully applied for certification of an existing well and proposed a plan to start production in the short term by connecting a 6,000 barrel per day Early Production Facility to the Alpine Pipeline.

In a sixth plan of development submitted to state officials in early October, the company said it believes it can complete that temporary system by the second quarter of 2019.

The state Division of Oil and Gas has yet to approve the plan.

Initial production from 3 wells

The temporary system would produce from three existing wells: North Tarn No. 1A, Mustang No. 1 and SMU M-02. Some work is required on two of those wells before they could begin producing. BRPC said it needs to drill either a lateral extension or a sidetrack at Mustang No. 1 and said it needs to perforate and stimulate SMU M-02 before start-up.

During the initial field commissioning, BRPC expects to pre-produce from the SMU M-02 well in order to better understand the Kuparuk A sands. The company described its intention to flare any excess gas during this period. After the flaring plan first appeared in a revised plan earlier this year, the state Division of Oil and Gas rejected the proposal.

The earlier plan had also included a proposal to truck oil for processing and sales until a pipeline system could be completed. The state also challenged that idea, saying that trucking costs would likely be ineligible for the transportation deductions built into royalty costs. The trucking proposal does not appear in the newest plan of development.

BRPC said it plans to drill as many as four new wells at the Southern Miluveach unit in the second half of 2019, as part of its initial development campaign for the Mustang field.

Longer-term plans for Mustang include installation of a 15,000-bpd central processing facility, completion of drill site facilities, construction of two pipelines and implementation of a 21-well development program with 10 producers and 11 injectors.

Brooks Range Petroleum operates the Southern Miluveach unit on behalf of working interest owners CaraCol Petroleum LLC, TP North Slope Development LLC, Nabors Drilling Technologies USA Inc., AVCG, LLC, Mustang Road LLC and MOC1 LLC.

—ERIC LIDJI

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GMT-1 START

the NPR-A," said Joe Marushack, president of ConocoPhillips Alaska, when announcing the start of production. "The GMT-1 team successfully and safely executed this project in an environmentally responsible manner. We appreciate the collaboration with stakeholders from Kuukpik Corporation, the community of Nuiqsut, the North Slope Borough and ASRC that made it possible."

"The onset of oil production at GMT-1 is good news for Alaskans who will benefit from new jobs and increased production in the trans-Alaska pipeline," said Gov. Bill Walker. "The Department of Natural Resources played a key role in permitting this project and is working with industry, local communities, and federal agencies on other promising oil prospects in the NPR-A."

The GMT-1 development involves an 11.8-acre drilling pad, with a 7.6-mile road to the CD-5 pad. The GMT-1 pad can support up to 33 wells, although initially it will only have nine wells. ConocoPhillips says that it anticipates the development having a total cost of about $725 million, including the cost of construction and drilling. Peak construction during the past two winters created about 700 jobs.

The project constitutes one of a chain of developments that ConocoPhillips is undertaking, progressively stepping out west into the northeastern part of the NPR-A from the Colville River delta. The idea is that, by gradually extending the oil infrastructure west, each new project becomes economically viable. The process began with the CD-5 development, the first well pad inside the NPR-A — CD-5 went into production in late 2015. GMT-1 is the next project in the sequence, to be followed by GMT-2, about eight miles southwest of GMT-1. BLM has published a final EIS for GMT-2 — ConocoPhillips now waiting for a BLM record of decision for that project.

The company says that construction for GMT-2 could begin in early 2019. Because GMT-2 has more wells than GMT-1, ConocoPhillips thinks that GMT-2's cost, estimated at more than $1 billion, will be higher than the cost of GMT-1. However, the GMT-2 anticipated peak production, at 35,000 to 49,000 barrels per day, will also be higher.

The project constitutes one of a chain of developments that ConocoPhillips is undertaking, progressively stepping out west into the northeastern part of the NPR-A from the Colville River delta.

Willow

The behemoth at the western end of the current chain of ConocoPhillips NPR-A developments is Willow, in the Bear Tooth unit. With an estimated peak production rate of 100,000 bpd, ConocoPhillips plans to develop Willow as a standalone field, with its own production facilities, rather than as another Alpine satellite. Scoping for the environmental impact statement for Willow is underway, with first production anticipated around 2024-25, if the development goes ahead. Initial development would likely cost $2 billion to $3 billion, with a further $2 billion to $3 billion required for full field development, ConocoPhillips has indicated. ●

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INSIDER

But, as she points out, the Slope's glory days are coming back: "IHS Markit recently forecast that the ANS could theoretically become a main source of US production in the next 8 years with an expected growth of nearly 40 percent."

Quoting IHS, she said the basin is an "arrested, late-emerging phase 'super basin' rather than a mature basin," noting the Slope's recoverable reserves improved six-fold in 2017 from the overlooked Nanushuk and Torok formation discoveries (by Armstrong/Repsol to be developed by Oil Search; ConocoPhillips; Caelus).

Quoting IHS, she wrote, "For onshore light-oil opportunities in a stable country with positive investment outlooks, the ANS provides a viable alternative to the competitive Lower 48 unconventional basins, where acreage prices are an order of magnitude greater and have transportation and raw material constraints, even if they are temporary."

"A black gold rush could inevitably occur with the recent super basin classification," Bell wrote, "making Alaska more than ready with its established infrastructure and skilled workers prepared."

—KAY CASHMAN

BP's top exec sees good times ahead for o&g

FOLLOWING ARE OBSERVATIONS and quotes from press outlets from BP chief executive Bob Dudley's presentation at the Oil & Money conference in London Oct.9:

BOB DUDLEY

•BP is planning its investments at $60-$65 a barrel oil, increasing it from $50-$55 last year, and although Dudley doesn't expect sustained prices of $85, he said prices are unlikely to plummet again.

•Each of BP's projects will make money at less than $40 oil by 2021.

•"Renewables are growing at a remarkable rate," and could supply about a third of energy needs by around 2040. "But we (oil and gas producers) still need to meet the remaining two-thirds of demand," Dudley said.

—KAY CASHMAN

Gulfstream releases video of polar flight

IN MAY THE GULFSTREAM G650ER set a speed record over the North Pole, linking the Atlantic and Pacific, via White Plains, New York to Shanghai.

Gulfstream Aerospace released a video in the second week of October on Facebook, Twitter and other sites of the record-breaking 6,870-nautical-mile polar flight.

The jet flew at an average speed of Mach 0.86, taking just 13 hours and 40 minutes to reach its destination.

—KAY CASHMAN

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PRUDHOE TECHNOLOGY

next year. And BP is working with other companies operating on the North Slope to continue to figure out ways to viably produce more of the viscous oil that exists in large quantities on the Slope, Wirnkar said.

Recent major oil discoveries on the Slope have also upped assessments of how much North Slope oil remains to be developed, a factor that can also support the longevity of BP's involvement in the region, Wirnkar commented.

Excited about gas

Wirnkar said BP is very excited about the state's efforts to monetize North Slope natural gas through the Alaska LNG project. If all of the partners in the Prudhoe Bay field sign on for the sale of gas for export, there is the potential to eventually produce about 30 trillion cubic feet of gas from the field, he said. He said that BP is working closely with the Alaska Oil and Gas Conservation Commission, showing the commission the company's computer model that forecasts when gas production from Prudhoe Bay may become more economical than oil production. However, that changeover date is not a fixed target and can change, if new oil reserves are established in the field, Wirnkar said.

Evolution of the field

Whereas, when Prudhoe Bay first went into operation, the field reservoir pressure was high and there was a 600-foot oil column, production over the years has lowered the pressure, while the remaining oil in place has fragmented into a series of relatively small pockets. Waterflood and gas injection have been used to sustain the reservoir pressure to levels where oil production can continue. Currently BP recycles about 8 billion cubic feet of gas per day through the field reservoir — without that gas recycling and injection, the field would no longer produce any oil, Wirnkar said.

Continued operation depends on efficiently, economically and safely developing the resources that are known to exist, while also seeking new opportunities for growth, he said. "There is still a lot that we can do here," Wirnkar said.

State-of-the-art technology

Locating and exploiting the remaining small pockets of oil in the field requires state-of-the-art technology in the form of data acquisition, storage and analysis, and in the form of sophisticated drilling techniques.

Modern seismic surveying, of the type that BP is about to conduct at Prudhoe Bay, produces crisp images, clearly showing faults and other subsurface features, enabling the location of features where fur-

As part of its commitment to Prudhoe Bay, BP is going to conduct a new 3-D seismic survey across the field during the coming winter. The company is also bringing in two new drilling rigs next year.

ther oil may be found. Then, multilateral wells, drilled out from single wells connecting to the surface, can thread though these remaining pockets of oil. At the same time, the seismic imaging can enable, for example, the precise injection of water into areas where it can be most effectively used.

Data acquisition and processing are also coming to the aid of maintenance efficiency: BP is transitioning to the use of what is termed "predictive maintenance analytics," a data intensive technology that enables the prediction of equipment failures before failures happen. This approach improves efficiency by increasing equipment up time, Wirnkar said.

Importance of efficiency

And, in the competitive world of the oil industry, efficiency is a key to success. Last year BP increased its operational efficiency by 5 percent at Prudhoe Bay, thus increasing the flow of oil through the trans-Alaska pipeline. In fact, over the past couple of years the company arrested the field's production decline.

Although the oil price is currently above $80 per barrel, BP thinks that, as the oil market changes, the price will drop again at some stage. Continuing efficiency can ensure that field operations remain viable at lower oil prices. Moreover, efficiency at Prudhoe Bay is critical to the field's ability to compete with oil production in the Lower 48. And competition with the Lower 48 is particularly challenging, because, with the oil service companies tending to focus their efforts on the Lower 48, those services tend to be relatively expensive in Alaska, Wirnkar said.

Wirnkar also expressed BP's concern about the upcoming state ballot measure relating to salmon habitat — this measure, if passed, could have an impact on, for example, the company's ability to carry out timely maintenance projects on some of its facilities, he said. He also cautioned about the need for stable taxation for the oil industry in Alaska.

But BP remains optimistic about its Alaska operations.

"We are very, very excited," Wirnkar said. "We want to be here for the next 40 years."

—ALAN BAILEY

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