Petroleum news

page 3 February ANS output down 1.3% from January; Cook Inlet up

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The 'Beast' headed to Alpine to spud first ERD well in late April

Doyon Drilling's new extended reach drilling rig is on its way to the North Slope Colville River unit to spud its first well in late April for ConocoPhillips Alaska.

From CD2 pad, the giant ERD rig will target the Fiord West Kuparuk reservoir, which was discovered in 1996, but because it's in an environmentally sensitive area along the coast it couldn't be accessed.

Rig 26, which is being transported in seven modules, can drill targets some 7 miles from its surface location, whereas other rigs are designed to drill about 22,000 feet from a pad. This means the 9.5 million pound high-tech ERD rig will be able to develop 154 square miles of reservoir versus the standard 55 square miles.

see **ERD RIG** page 12

Furie/Kachemak asset sale craters; HEX, with AIDEA loan, in running

An acquisition by foreclosure agreement between Chapter 11 debtor Furie Operating Alaska LLC and acquirer Kachemak Exploration LLC for the sale of Furie's Cook Inlet assets appears to have broken down.

Kachemak — a Delaware corporation recently formed by GFR Holdings of Fort Worth, Texas, and Melody Capital Partners L.P. — is seeking to acquire the Cook Inlet Kitchen Lights offshore unit, related infrastructure such as the Julius R offshore natural gas platform, together with an onshore processing facility and related pipelines.

According to a Law360 report, Furie told Judge Laurie Selber Silverstein that the deal collapsed last week, during a March 25

see **FURIE SALE** page 9

Kenai refinery turnaround delayed to fall due to coronavirus concerns

Marathon Petroleum Corp. said it has postponed a mid-April turnaround operation at its Kenai refinery due to coronavirus concerns.

"It's a pretty extraordinary measure," Casey Sullivan, Marathon government and public affairs manager, told Petroleum News March 24. "This is a program that is tens and tens of millions of dollars; it's hundreds and hundreds of contractors; it's kind of a big ship and it is a hard thing to turn — or turn off.

"Lots of things in the air. We've been able to do it, with teams working really hard to do that ... to pause it as best you can."

The company plans to get the turnaround back on the

see **KENAI REFINERY** page 8

DEC hears concerns regs would be weakened, others urge updating

Last year the Alaska Department of Environmental Conservation sought input on requirements for its oil discharge prevention and contingency plan requirements. The department said that based on feedback it "may consider amending contingency plan regulations" in 18 Alaska Administrative Code 75, Article 4, and said it was "also accepting comments on the related statutes that authorize the Article 4 regulations."

"I've heard from many Alaskans that contingency plans are unnecessarily burdensome while lacking corresponding environmental benefits," ADEC Commissioner Jason Brune said. "To achieve Governor Dunleavy's goal of being open for busi-

see **CONTINGENCY PLANS** page 7

EXPLORATION & PRODUCTION

Juggling windows

Jade's plan schedules Sourdough work to maintain economic viability

By KAY CASHMAN

Petroleum News

ERIK OPSTAD

TOM STOKES

A couple of days after it was filed on March 17 Alaska's Division of Oil and Gas approved Jade Energy's second Plan of Development for the Sourdough prospect on the southeastern edge of the Point Thomson unit.

Jade is both the majority owner of and operator of PTU Tract 32 in Area F of the eastern North Slope lease ADL 343112.

Tract 32 holds two mid-1990's oil discovery wells, Sourdough 2 and 3, that were drilled by BP, which at the time estimated the prospect held 100 million barrels of recoverable oil.

The essential difference in Jade's new POD, which covers the period April 1 through Dec. 31, is to drill the first new Sourdough appraisal well, Jade 1, in the winter of 2021-22, versus next winter. Jade worked closely with the division to come up with a plan that maintained the economic viability of the project, which is the furthest east of all North Slope developments.

see **SOURDOUGH** page 11

UTILITIES

SB 123 goes to governor

Legislature passes bill enabling formation of electric reliability organization

By ALAN BAILEY

For Petroleum News

The Alaska Legislature has passed Senate Bill 123, a bill designed to enable the formation of an electric reliability organization, in particular for the Alaska Railbelt electricity system. The bill also enacts a statute that gives the Regulatory Commission of Alaska authority to regulate the construction of new major generation and transmission facilities in the electricity grid, and to regulate integrated resource planning for the system. The bill now goes to the governor for his signature.

The purpose of the legislation is to ensure a more coordinated and efficient approach to the overall management and operation of the electrical system in the Railbelt, to minimize the cost of electricity for consumers while also assuring a high level of supply reliability.

In December all six of the Railbelt utilities signed a memorandum of understanding for the formation of the Railbelt Reliability Council, in effect an electric reliability organization for the Railbelt.

In passing SB 123 the legislators added the text of another bill, Senate Bill 81, presumably to allow the simultaneous passage of both bills. SB 81

see **SB 123** page 10

GOVERNMENT

Waiting game for Alberta

No sign of promised O&G sector bailout beyond individual, company support

By GARY PARK

For Petroleum News

JASON KENNEY

Facing growing unease as the spread of COVID-19 accelerates and its economic underpinning crumbles, energy-driven Alberta is waiting for the Canadian government to deliver a promised bailout package to keep the province's oil and gas industry functioning.

A spokeswoman for Natural Resources Minister Seamus O'Regan said all options are being weighed, including financial backing for skilled workers to remediate the environmental liabilities associated with abandoned, or orphan wells.

So far, the government of Prime Minister Justin Trudeau has limited itself to gaining approval of Parliament in an emergency session to release C$27 billion in direct support for individuals and companies and grant C$55 billion in deferred taxes.

But Trudeau was forced by the opposition parties to back off a measure that would have given the government sweeping new powers for the next 21 months to unilaterally spend, borrow and tax Canadians without obtaining the approval of Parliament.

In the midst of this swirl the Trudeau administration released C$5 billion for the agriculture sec-

see **WAITING GAME'** page 10

● EXPLORATION & PRODUCTION

BLM issues supplement to Willow draft EIS

Biggest change is elimination of construction of module transfer island in favor of using existing Oliktok Dock to land sealift

By KRISTEN NELSON

Petroleum News

The federal Bureau of Land Management has released a supplement to the draft environmental impact statement for ConocoPhillips Alaska's proposed Willow master development plan.

BLM said changes were made by the company in response to multiple stakeholder concerns and public comments on the draft EIS released last year.

The updated proposal has design adjustments for many project components, but primarily addresses a revision removing construction of a module transfer island which was analyzed as Alternative B of the draft EIS, BLM said.

ConocoPhillips is now proposing that modules be transported via sealift to Oliktok Point, which has an existing dock and from there by ice road across the Colville River. The company has also added construction of a freshwater reservoir and up to three boat ramps to support subsistence activities.

BLM said module delivery using Oliktok Dock and sea ice roads was previously evaluated but eliminated due to constraints related to module size and sea ice road limitations across the Colville River Delta.

An additional scenario would have used the existing Oliktok Dock and moved modules to the project area using existing gravel roads and some 165 miles of ice roads routed south through an area near Umiat, but was eliminated when BLM was unable to confirm the route would allow for a fully grounded ice road across the river.

Since alternatives developed for the draft EIS, BLM said, ConocoPhillips has collected additional data on flow and ice conditions at Ocean Point, and the company "is now confident that transporting sealift modules via an ice road across the Colville River near Ocean Point is feasible and have made this option part of their proposed Project."

Comments close in May

BLM said the new proposal was received in November, shortly after the comment period closed on

see WILLOW EIS page 4

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ON THE COVER

ENVIRONMENT & SAFETY

EXPLORATION & PRODUCTION

INTERNATIONAL

● EXPLORATION & PRODUCTION

ANS production down 1.3% month-over-month

North Slope crude, natural gas liquids average 522,421 bpd for February, down 1% year-over-year; Cook Inlet up 1% at 14,116 bpd

By **KRISTEN NELSON**
Petroleum News

Alaska North Slope production averaged 522,421 barrels per day in February, down 1.3%, 6,796 bpd, from a January average of 529,217 bpd and down 1% from a February 2019 average of 577,644 bpd. ANS crude oil production averaged 462,549 bpd, down 1.3%, 5,897 bpd, from a January average of 468,446 bpd, and down 2.1% from a February 2019 average of 472,457 bpd. Natural gas liquids production averaged 59,872 bpd, down 1.5%, 899 bpd, from a January average of 60,770 bpd but up 8.5% from a February 2019 average of 55,187 bpd.

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

Few month-over-month increases

Just a handful of North Slope fields showed month-over-month production increases.

Northstar has the highest percentage of NGLs on the North Slope, 30.6% of its production in February, compared to 20% at Prudhoe and 12.5% at Endicott.

Point Thomson, operated by ExxonMobil Production, averaged 5,774 bpd in February, up 9.1%, 482 bpd, from a January average of 5,292 bpd, but down 34.3% from a February 2019 average of 8,784 bpd. The field produces condensate from a high pressure reservoir, reinjecting gas, and has rarely produced at the facility's rated 10,000 bpd. The company told the state in its most recent plan of development (see story in Nov. 17, 2019, issue of Petroleum News) that it is addressing issues in its gas injection equipment, has begun installing upgraded components and expects to receive and install the remaining equipment during the 2020-21

see **ANS PRODUCTION** *page 5*

Cook Inlet natural gas production up by 5%

Natural gas production in Alaska's Cook Inlet averaged 223,304 thousand cubic feet per day in February up 4.9%, 6,022 mcf, from a January average of 217,174 mcf and up 3.3% from a February 2019 average of 216,146 mcf per day.

Seven fields account for 83% of Cook Inlet natural gas production. From largest to smallest they are: Ninilchik, Kenai, Swanson River, McArthur River, North Cook Inlet, Beluga River and Kitchen Lights.

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.

Hilcorp Alaska's Ninilchik field averaged 43,083 mcf per day in February, up 11%, 4,284 mcf, from a January average of 38,800 mcf per day, and up 14.5% from a February 2019 average of 37,618 mcf.

Hilcorp's Kenai field averaged 34,471 mcf per day in February, up 3.3%, 1,103 mcf, from a January average of 33,368 mcf per day and up 6% from a February 2019 average of 32,523 mcf per day.

Hilcorp's Swanson River averaged 34,254 mcf per day in February, down 0.1%, 28 mcf, from a January average of 34,283 mcf per day and down 1% from a February 2019 average of 34,534 mcf per day.

Hilcorp's McArthur River, the inlet's largest oil producer, averaged 20,718 mcf per day of natural gas in February, down 4.1%, 892 mcf per day, from a January average of 21,610 mcf and down 15.2% from a February 2019 average of 24,439 mcf per day.

Hilcorp's North Cook Inlet field averaged 19,071 mcf per day in February, up 8.8%, 1,542 mcf, from a January average of 17,529 mcf per day, and up 28.4% from a February 2019 average of 14,851 mcf per day.

The Beluga River field, operated by Hilcorp, averaged 18,717 mcf per day in February, down 0.3%, 55 mcf, from a January average of 18,773 mcf per day and down 32.1% from a February 2019 average of 27,567 mcf per day.

Furie's Kitchen Lights averaged 14,360 mcf per day in February, down 1%, 136 mcf per day, from a January average of 14,496 but up 21,219% from February 2019, when the field was basically down due icing in lines and averaged 67 mcf per day.

Hilcorp's Beaver Creek averaged 7,051 mcf per day in February, up 1.6%, 108 mcf, from a January average of 6,944 mcf per day but down 16% from a February 2019 average of 8,391 mcf.

Kenai Loop, operated by AIX, averaged 5,219 mcf per day in February, down marginally from an average of 5,223 mcf in January and down 4.5% from an average of 5,468 mcf per day in February 2019.

Hilcorp's Cannery Loop averaged 4,779 mcf per day in February, down 10.6%, 566 mcf, from a January average of 5,344 mcf but up 5.2% from a February 2019 average of 4,542 mcf per day.

BlueCrest's Hansen field averaged 4,566 mcf per day in February, down 3.9%, 187 mcf, from a January average of 4,753 mcf and down 53% from a February 2019 average of 9,722 mcf per day.

Hilcorp's Deep Creek averaged 4,113 mcf per day in February, up 2.9%, 115 mcf, from a January average of 3,998 mcf per day but down 8.7% from a February 2019 average of 4,506 mcf per day.

see **INLET PRODUCTION** *page 6*

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WILLOW EIS

the draft EIS.

The supplement to the DEIS presents the new information and allows for a 45-day public comment period, starting March 20 and closing May 4 at 11:59 p.m. Alaska time.

The master development plan for Willow describes a project with up to five drill sites, a central processing facility, an operations center pad, gravel roads, ice roads during construction and resupply ice roads during operations, one to two airstrips, pipelines and a gravel mine site.

The project would have peak production in excess of 160,000 barrels of oil per day, with a processing capacity of 200,000 barrels per day, over the project's 30-31 year life, and would produce some 590 million total barrels of oil.

The Willow project is in the northeast area of the National Petroleum Reserve-Alaska.

The draft EIS analyzed a no action alternative and three action alternatives — B, C and D — along with two module delivery options, 1 and 2.

The supplement addresses three project components added after the DEIS was published: a third option for module delivery; a constructed freshwater reservoir; and up to three boat ramps for subsistence access.

Changes to be considered in final EIS

BLM said some project updates and modifications are not included in the supplement to the DEIS but will be detailed in the final EIS.

BLM said the Colville River ice bridge is planned for an area currently used by the North Slope Borough to build a portion of the community winter access trail connecting North Slope communities with the Alaska highway system.

Those include: possible shift of production from Greater Mooses Tooth 2, currently under production, from the Alpine processing facility to the Willow processing facility; two additional water sources; Willow operations center and airstrip relocation some 2.5 miles to northeast under alternative B (the company's proposal); refinements to reduce overall size of the Tinmiaqsiugvik mine site; refinements to overall project footprint; updates to total traffic and freshwater use estimates; new project facilities added which would be placed on existing gravel pads in Alpine and Kuparuk; updates to ice road design; and updates to project schedule and construction sequencing, which do not, BLM said, change the anticipated life of the project or the project start date.

Module delivery option 3

There were two module delivery options considered in last year's DEIS — both were transfer islands for the modules.

BLM said ConocoPhillips developed a new module delivery option in response to concerns and comments from stakeholders.

Under the new option 3, Colville River crossing, large sealift modules would be delivered at the existing Oliktok Dock and transported over the existing gravel road network in Kuparuk south to Kuparuk drill site 2P, and from there transported via ice road across the Colville River to the project area near the Greater Mooses Tooth 2 drill site and from there over project gravel roads or ice roads (depending on the alternative) to their installation location.

Sealift barges would deliver processing modules to Oliktok Dock under the new delivery option, with delivery occurring during the two summer seasons of 2024 and 2026 (for alternatives B and C) or 2025 and 2027 (alternative D).

Lightering barges would be used because the 8-foot water depth at Oliktok Dock is too shallow to accommodate fully laden sealift barges, requiring a portion of each sealift barge load to be transferred onto a lightering barge — which has shallower draft requirements — for transport to Oliktok Dock.

Screeding, redistribution or recontouring of sea floor to provide a level surface for the barges to be grounded during load transfers, would be required.

Lightering transfer would be some 2.3 miles north of Oliktok Dock in 10 feet of water; screeding would also be required in that area, as well as some 2.5 acres in front of Oliktok Dock to facilitate unloading of lightering barges.

Some improvements and modifications would be required at Oliktok Dock: the existing dock surface would be raised some 6 feet and two new 50-ton bollards would be installed.

Temporary storage

After the sealift modules are delivered to Oliktok Dock they would be moved to and stored at an existing 12-acre gravel pad 2 miles south of the dock. Prior to that move, gravel would be added to the storage area, currently 3-4 feet thick, to bring it up to 5 feet and rig mats would be installed to provide further structural support for module storage. The modules would be skirted to prevent drifting snow from accumulating under them.

In January the modules would be transported on existing gravel roads to Kuparuk drill site 2P, where they would be staged on an ice pad until construction of module transport ice roads and the Colville River ice bridge are complete.

Ice road, river crossing

A module transport ice road would be 60 feet wide and 40.1 miles long. It would be constructed from both ends — drill site 2P in Kuparuk and GMT-2 in NPR-A, with segments meeting at the Colville River crossing near Ocean Point.

An engineered ice bridge would provide enough load-carrying capacity to support both the sealift modules and the self-propelled module transporters.

The grounded ice crossing would be downstream from Ocean Point, sited to be upstream of saltwater intrusion and tidal backwatering from the Colville River Delta in an area not expected to be used by fish in winter.

The river ice crossing would be approximately 2,800 feet from the top of the east bank to the top of the west bank, some 700 feet from the edge of water to edge of water, and 65 feet wide at the surface.

BLM said the Colville River ice bridge is planned for an area currently used by the North Slope Borough to build a portion of the community winter access trail connecting North Slope communities with the Alaska highway system.

The agency said ConocoPhillips would work with the NSB and local residents to ensure access is provided, with coordination in a manner similar to current practices for the annual Alpine resupply ice road.

A 100-person camp would be required near the drill site 2P access road to support module moves, with ice road construction crews for the eastern segment based out of the same camp near DS2P and ice road crews building the western segment based out of one of the construction camps used to support other project construction activity.

From GMT-2 to the Willow processing facility the modules would move on the proposed project access road.

BLM said ConocoPhillips has identified some curves on existing Kuparuk gravel roads that would need to be widened to accommodate the turning radius of the 200-foot-long self-propelled module transporters, requiring additional gravel and extension of culverts as needed.

Timing

ConocoPhillips said in July that it expected a final investment decision on the project in 2021 and first oil in 2025-26.

Alternative B is ConocoPhillips' proposal.

Alternatives C and D were developed for the draft EIS.

Alternative C would have the same gravel road between GMT-2 and Willow but would not have a gravel road connection from Willow to Bear Tooth drill site 1, although a gravel road would connect the BT1 drill site to the BT4 drill site, with an ice road constructed annually from the Willow processing facility to BT1.

Alternative D would not have gravel road access from GMT2, but would have the same gravel infield roads as Alternative B.

Gravel haul and modifying existing roads would occur during summer 2023 under Alternatives B and C, BLM said, and summer 2024 under Alternative D.

Modules for the Willow processing facility and drill sites BT1 through BT3 would be delivered by sealift barge in the summer of 2024 for Alternatives B and C, and in 2025 for Alternative D.

A second sealift would deliver modules for drill sites BT4 and BT5 in summer 2026 for Alternatives B and C, and in summer 2027 for Alternative D. ●

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ANS PRODUCTION

plan period.

Milne Point, operated by Hilcorp Alaska, averaged 31,960 bpd in February, up 0.7%, 231 bpd, from a January average of 31,729 bpd and up 38.3% from a February 2019 average of 23,108 bpd. Hilcorp took over operatorship at Milne and a 50% working interest in 2014 — when the field was averaging some 18,400 bpd. The company said in February that it expects to reach 40,000 bpd at the field by the end of 2020 (see story in March 1 issue of Petroleum News).

Endicott, also operated by Hilcorp, averaged 7,225 bpd in February, up 1.6%, 116 bpd, from a January average of 7,109 bpd, but down 3.8% from a February 2019 average of 7,508 bpd. Crude oil production at Endicott averaged 6,316 bpd in February, up 1.7%, 105 bpd, from a January average of 6,211 bpd but down 2.7% from a February 2019 average of 6,489 bpd. NGL production averaged 909 bpd, up 1.2%, 11 bpd, from a January average of 898 bpd, but down 10.8% from a February 2019 average of 1,019 bpd.

Other fields down month-over-month

All other ANS fields showed month-over-month production drops.

The largest percentage drop, 5.5%, was at Eni's Oooguruk field, which averaged 8,672 bpd in February, down 501 bpd from a January average of 9,173 bpd and down 5.3% from a February 2019 average of 9,155 bpd.

ConocoPhillips Alaska's Colville River averaged 51,206 bpd in February, down 5.2%, 2,778 bpd, from a January average of 53,984 bpd and down 3.5% from a February 2019 average of 53,053 bpd.

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

Badami, operated by Savant Alaska, a Glacier Oil & Gas company, averaged 1,357 bpd in February, down 3.8%, 53 bpd, from a January average of 1,410 bpd and down 25.6% from a February 2019 average of 1,823 bpd.

Northstar, operated by Hilcorp, averaged 9,925 bpd in February, down 3.4%, 347 bpd, from a January average of 10,271 bpd, and down 14.1% from a February 2019 average of 11,553 bpd. The field averaged 6,888 bpd of crude oil in February, down 0.6%, 41 bpd, from a January average of 6,929 bpd and down 18.9% from a February 2019 average of 8,496 bpd, and averaged 3,036 bpd of NGLs in February, down 9.2%, 306 bpd, from a January average of 3,342 bpd and down 0.7% from a February 2019 average of 3,057 bpd. Northstar has the highest percentage of NGLs on the North Slope, 30.6% of its production in February, compared to 20% at Prudhoe and 12.5% at Endicott.

ConocoPhillips' Greater Mooses Tooth, in the National Petroleum Reserve-Alaska, averaged 5,105 bpd in February, down 3%, 158 bpd, from a January average of 5,264 bpd and down 59.2% from a February 2019 average of 12,526 bpd.

The ConocoPhillips-operated Kuparuk River field averaged 101,913 bpd in February, down 2.7%, 2,802 bpd, from a January average of 104,716 bpd and down 5.3% from a February 2019 average of 107,582 bpd.

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

Eni's Nikaitchuq field averaged 20,044 bpd in February, down 1.1%, 221 bpd, from a January average of 20,265 bpd but up 16.2% from a February 2019 average of 17,244 bpd.

The BP Exploration (Alaska)-operated Prudhoe Bay field, the Slope's largest, averaged 279,241 bpd in February, down 0.3%, 764 bpd, from a January average of 280,004 bpd but up 1.4% from a February 2019 average of 275,307 bpd. Prudhoe production includes an average of 223,314 bpd of crude, down 0.1%, 160 bpd, from a January average of 223,474 bpd and down 0.4% from a February 2019 average of 224,196 bpd, and 55,927 bpd of NGLs, down 1.1%, 604 bpd, from a January average of 56,530 bpd but up 9.4% from a February 2019 average of 51,111 bpd.

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.

Cook Inlet production up marginally

Cook Inlet production averaged 14,116 bpd in February, up 0.8%, 114 bpd, from a January average of 14,003, but down 6.7% from a February 2019 average of 15,134 bpd.

Of the inlet's nine oil fields, six had no change or showed an increase, while three were down month-over-month — with seven of the nine down year-over-year.

Hilcorp's Swanson River field averaged 938 bpd in February, up 21.8%, 168 bpd, from a January average of 770 bpd but down 11.8% from a February 2019 average of 1,063 bpd.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 1,140 bpd in February, up 6.2%, 66 bpd, from a January average of 1,073 bpd but down 18.4% from a February 2019 average of 1,396 bpd.

Redoubt Shoal, operated by Cook Inlet Energy, a Glacier Oil & Gas company, averaged 1,303 bpd in February, up 5.4%, 66 bpd, from a January average of 1,237 bpd, but down 12.9% from a February average of 1,496 bpd.

Hilcorp's Middle Ground Shoal averaged 1,260 bpd in February, up 2.3%, 29 bpd, from a January average of 1,231 bpd, but down 11.4% from a February 2019 average of 1,422 bpd.

Hilcorp's Granite Point averaged 3,348 bpd in February, up 1.2%, 40 bpd, from a January average of 3,308 bpd and up 27.6% from a February 2019 average of 2,624 bpd.

Hilcorp's Beaver Creek averaged 222 bpd in February, unchanged from January, but down 35.8% from a February 2019 average of 346 bpd.

West McArthur River, operated by Glacier's Cook Inlet Energy, averaged 331 bpd in February, down 10.2%, 37 bpd, from a January average of 368 bpd and down 52.1% from a February 2019 average of 690 bpd.

Hilcorp's McArthur River, Cook Inlet's largest, averaged 4,275 bpd in February, down 3.9%, 172 bpd, from a January average of 4,447 bpd and down 11.1% from a February 2019 average of 4,810 bpd.

Hilcorp's Trading Bay averaged 1,300 bpd in February, down 3.3%, 45 bpd, from a January average of 1,345 bpd but up 1% from a February 2019 average of 1,287 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 ●

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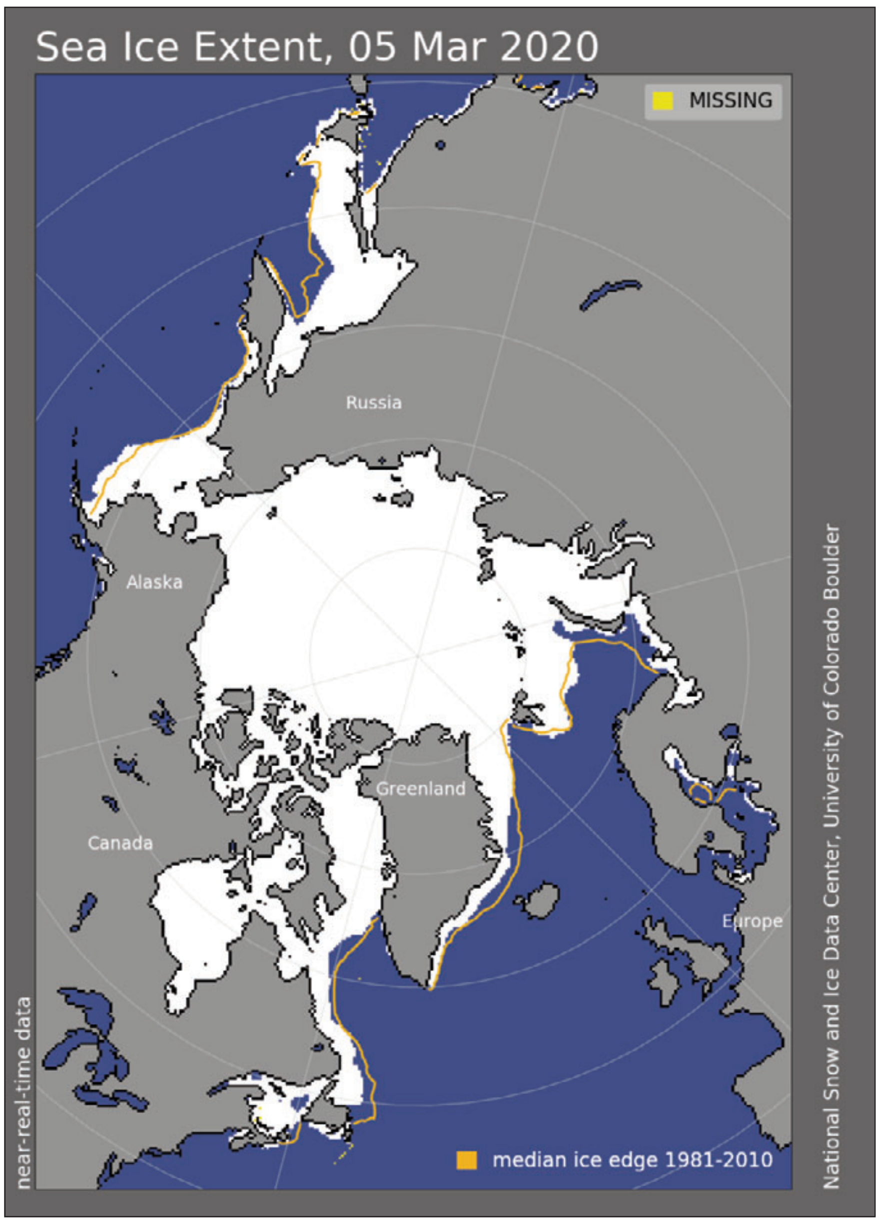
ENVIRONMENT & SAFETY



Preliminary sea ice extent 11th lowest

Arctic sea ice likely reached its maximum extent for the year at 5.81 million square miles on March 5, scientists at the National Snow and Ice Data Center at the University of Colorado Boulder said in a March 24 release.

That maximum, a preliminary number, is the eleventh lowest in the 42-year satellite record.

NSIDC said continued winter conditions could push the ice extent higher. It will issue a formal announcement at the beginning of April including a full analysis of possible causes behind this year's ice conditions.

While this year's extent is the 11th lowest on record, it is the highest since 2013. The 5.81 million square mile extent is 228,000 square miles below the 1981 to 2010 average maximum of 6.04 million square miles and 247,000 square miles above the lowest maximum of 5.56 million square miles set in 2017.

Prior to 2020, the center said, the four lowest maximum extents occurred from 2015 to 2018.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

US drilling rig count drops 20 to 772

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. the week ending March 20 was down by 20 from the previous week to 772 and down by 244 from 1,016 a year ago.

In its weekly rig count the Houston oilfield services company said 664 rigs targeted oil, down 19 from the previous week and down by 160 from a year ago, while 106 targeted natural gas, down one from the previous week and down 86 from a year ago. There were two miscellaneous rigs active, unchanged from the previous week and up by two from a year ago.

The company said 49 of the holes were directional, 696 were horizontal and 27 were vertical.

The rig count in Texas, the state with the most active rigs at 397, was down by 11 from the previous week.

New Mexico (112 rigs) was down by five rigs from the previous week; Oklahoma (43 rigs) was down by three; and North Dakota (50 rigs) was down by one.

Rig counts were unchanged from the previous week in Alaska (10 rigs), California (12 rigs), Colorado (21 rigs), Louisiana (47 rigs), Ohio (nine rigs), Pennsylvania (24 rigs), Utah (seven rigs), West Virginia (15 rigs) and Wyoming (20 rigs).

The 10-rig count Baker Hughes shows for Alaska for the week ending March 20 is up one from a year ago.

The U.S. rig count peaked at 4,530 in 1981. It bottomed out in May 2016 at 404.

—KRISTEN NELSON

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INLET PRODUCTION

North Fork, operated by Cook Inlet Energy, a Glacier Oil & Gas company, averaged 3,715 mcf per day in February, up 15.2%, 490 mcf, from a January average of 3,225 mcf per day, but down 5.1% from a February 2019 average of 3,916 mcf per day.

Hilcorp's Granite Point averaged 3,465 mcf per day in February, up 5%, 167 mcf, from a January average of 3,299 mcf per day and up 19.5% from a February 2019 average of 2,901 mcf per day.

Hilcorp's Trading Bay averaged 2,920 mcf per day in February, up 14.9%, 380 mcf, from a January average of 2,540 mcf per day but down 2.1% from a February 2019 average of 2,982 mcf per day.

Hilcorp's Lewis River averaged 1,113 mcf per day in February, down 24%, 352 mcf, from a January average of 1,465 mcf per day but up 368.3% from a February 2019 average of 238 mcf per day.

Hilcorp's Nikolaevsk averaged 434 mcf per day in February, up 4.9%, 20 mcf, from a January average of 414 mcf per day and up 1.5% from a February 2019 average of 427 mcf per day.

Hilcorp's Ivan River averaged 376 mcf per day in February, up 19%, 60 mcf, from a January average of 316 mcf per day, and up 1.7% from a February 2019 average of 370 mcf per day.

Hilcorp's Middle Ground Shoal averaged 278 mcf per day in February, up 19.7%, 46 mcf, from a January average of 232 mcf per day but down 12.5% from a February 2019 average of 317 mcf per day.

Redoubt Shoal, operated by Glacier's Cook Inlet Energy, averaged 271 mcf per day in February, down 0.8%, 2 mcf, from a January average of 274 mcf per day but up 12.1% from a February 2019 average of 242 mcf per day.

Amaroq's Nicolai Creek averaged 265 mcf per day in February, up 19.3%, 43 mcf, from a January average of 222 mcf per day but down 37.8% from a February 2019 average of 427 mcf per day.

West McArthur River, operated by Glacier's Cook Inlet Energy, averaged 63 mcf per day in February, down 8.8%, 6 mcf, from a January average of 69 mcf per day and down 38.4% from a February 2019 average of 102 mcf per day.

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

—KRISTEN NELSON

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CONTINGENCY PLANS

ness, today we are beginning a fully transparent scoping process seeking the public's input," he said in an Oct. 15 release.

Responses covered a spectrum from concern about exposing the state to another major oil spill to requests for consistent treatment by ADEC plan reviewers and a desire to see regulations reflect current technology.

A number of responses referred to the 1989 Exxon Valdez oil spill and the federal Oil Pollution Act of 1990 which established the regional citizens' advisory councils.

A number of responses referred to the 1989 Exxon Valdez oil spill and the federal Oil Pollution Act of 1990 which established the regional citizens' advisory councils.

Prince William Sound RCAC

In its comments the Prince William Sound Regional Citizens' Advisory Council said it "does not think the regulations are necessarily flawed as they are written," and noted that "some plan holders and response action contractors have become frustrated with inconsistencies in the interpretation, implementation, and enforcement of the ODPCP regulations."

Some of those frustrations, the council said, stem from differences in requirements for large and complex operations as compared to those for smaller, less complex operations, "but much of it stems from different expectations of individual ADEC plan reviewers. This frustration indicates that the problems are not with the regulations in and of themselves, but instead lie with training and supervision of ADEC plan reviewers."

The council said there has been a loss of experience and institutional continuity in recent years because of high turnover at ADEC, combined with organizational changes in the Division of Spill Prevention and Response, combining plan review and spill response, and requiring "staff to learn new tasks in a short time," resulting in inexperienced staff reviewing plans, increasing the time it takes and "exacerbating inconsistencies in the interpretation, implementation, and enforcement of the ODPCP regulations."

PWSRCAC commented extensively, and made a number of recommendations, among them that ADEC develop training to ensure "all plan reviewers are trained to interpret, implement, and enforce the regulations consistently."

Cook Inlet RCAC

"We believe that sweeping changes to the current requirements are not warranted," the Cook Inlet Regional Citizens' Advisory Council said in its comments, but said that in its years of reviewing plans and plan amendments and evaluating drills and exercises "and participating in other plan-related activities for a variety of operators, we have become concerned about the inconsistent application of regulatory requirements across plan holders," and noted that industry representatives have also shared these concerns in comments during the current scoping process.

CIRCAC said this highlights "the importance of consistent training and oversight of ADEC personnel charged with reviewing the plans," and, like the PWSRCAC, cited turnover at ADEC and reorganization in SPAR.

"CIRCAC recommends that ADEC develop and adopt a training regime that ensures consistency in interpretation, implementation, and enforcement of regulations," the council said.

AOGA recommends updating

The Alaska Oil and Gas Association, a trade association whose 14 member companies represent the industry in Alaska, said the current ODPCP regulations "require change in order to be relevant and reflect the current state of Alaska's oil exploration, production, pipelines, distribution and transportation industries," citing improvements in equipment and technology, and years of industry experience since they were enacted.

AOGA said it "supports modernization of the regulatory scheme" and said that would "eliminate unnecessary administrative compliances."

AOGA provided detailed comments, but in an overview listed revision and clarification of "oil terminal facility"; modernization of the administration of ODPCPs; modernization of prescribed industry standards, "which have not been revised since 2006 and are grossly outdated, to provide clear compliance standards"; revision of tank truck loading and permanent unloading area requirements; modernization of response planning standards; and elimination of best available technology analysis if plans "must be prepared in accordance with good engineering practice, including consideration of applicable industry standards, and if plans

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KENAI REFINERY

schedule before the end of 2020.

Sullivan said, given everything Marathon knows at this juncture, the turnaround can be rescheduled for fall or thereabouts.

"We'll kind of stage it as we need to — and of course we're working with all of our regulatory folks to make sure that the plan is appropriate," he said.

Sullivan said that Marathon is aware of and concerned about the disruption to the schedules of the participants in the turnaround, but the company is sure it has made the right decision under the circumstances.

"It's about health and safety; that's the bottom line," he said, adding, "The environment around us — the community where we live, and our employees ... the health and safety of both are paramount."

"It was a hard decision but it was absolutely the right decision."

"The leadership team did not take this decision lightly," Cameron Hunt, general manager of the Kenai refinery said in a March 18 release. "We are taking these extraordinary measures now to protect our people and the community, and to ensure the Marathon Kenai refinery continues to supply the state of Alaska with critical transportation fuels."

"The refinery team will continue to work the turnaround plans, and work with the appropriate regulatory agencies to ensure its next steps are safe and compliant with state and federal requirements," Hunt said. "We are actively working with our contractor support companies, regulatory agencies and community as we define our next steps in rescheduling this turnaround."

"The Kenai refinery is critical infrastructure for the state of Alaska, especially during these trying times," he said. "For more than 50 years, the refinery has safely, and reliably produced quality fuel products used to move Alaska."

Turnaround brings teams, specialists together from near and far

"When we do turnarounds, it's involved," Sullivan said.

"It's a regulatory, integrity-driven inspection," he said. "You do upgrades; you bring in lots of teams, specialists, from both local and from around the nation."

COURTESY MARATHON

Marathon Kenai refinery at dawn.

Many of these specialists are focused specifically on refinery turnarounds

"They specifically work on these; this is exactly what they do," Sullivan said.

Travel uncertainties, as a national approach to the COVID-19 pandemic unfolds, combined with the fact that some key specialists would be mobilized from out of state, contributed to the decision to defer the turnaround effort.

"Had we moved forward we would have brought in those teams," Sullivan said. "Some would have had to fly, but many are here locally, and some have been here for some time."

"It was just an abundance of caution," he said. "We operate at the pleasure of our community, and it just wasn't the right time to do it."

Not business as usual

Although the turnaround was delayed, the atmosphere around the refinery is not routine, Sullivan said, adding that Marathon is responding appropriately to the coronavirus as the company carries on refinery operations.

"We've implemented procedures to minimize any person-to-person contact," he said.

Marathon said the Kenai facility quickly implemented COVID-19 specific screening procedures, issued appropriate health practice advisories and implemented telecommuting for employees non-essential to critical day-to-day operations.

"The refinery team will continue to work the turnaround plans, and work with the appropriate regulatory agencies to ensure its next steps are safe and compliant with state and federal requirements," Hunt said. "We are actively working with our contractor support companies, regulatory agencies and community as we define our next steps in rescheduling this turnaround."

Sullivan said the company is following social distancing rules, even among close work associates.

"We really have the core group on their double shifts working to maintain the integrity of the refinery to keep operations going," he said. "It's a tight group."

Marathon does not anticipate any coronavirus-related interruptions to its usual feedstock supply to the refinery, Sullivan said. The facility uses every drop of Cook Inlet oil production, and it takes in crude from the North Slope, in addition to cargoes from the Bakken and elsewhere.

Sullivan said Marathon has also been a participant in contingency planning discussions with the Port of Anchorage, on strategies to ensure that the flow of goods needed in the state — including petroleum products — continues to move through Alaska's largest port to where it is needed.

Marathon is a significant user of the port's petroleum products and cement handling facilities.

Refining in Nikiski since 1969

The Kenai refinery, on Cook Inlet 60 miles southwest of Anchorage, began operations in 1969.

Since then, there has been more than a billion dollars of investment in the refinery that expanded its capacity, complexity and improved its environmental performance, including completion of a hydrocracker in 1980 and the launching of a ULSD, or ultra-low sulfur diesel, project in late November 2005.

Today the Kenai refinery at Nikiski employs 250 Alaskans, has a refining capacity of 68,000 barrels per day and produces gasoline and gasoline blendstocks, jet fuel, diesel fuel and heavy fuel oils, propane and asphalt.

A 70-mile, 48,000 bpd common-carrier products pipeline transports jet fuel, gasoline and diesel fuel to the Port of Alaska in Anchorage and the Ted Stevens Anchorage International Airport. Wholesale delivery occurs through terminals in Kenai, Anchorage, the Nikiski dock and the Port of Alaska.

It distributes these fuels from Nikiski to North Pole through a series of pipelines

In addition, the refinery supplies the network of Tesoro and USA Gasoline stations throughout Alaska.

Crude oil is delivered to the refinery by truck, double-hulled tankers through Cook Inlet and pipeline from the Kenai Peninsula and Cook Inlet.

In 2018, Marathon acquired the Kenai refinery when it merged in a takeover with Andeavor, a deal that closed later that year.

In the April 3 deal, Marathon agreed to buy rival Andeavor for $23.3 billion, creating the largest independent fuel maker in the United States, with an initial enterprise value greater than $90 billion.

—STEVE SUTHERLIN

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FURIE SALE

teleconference hearing in the U.S. Bankruptcy Court for the District of Delaware.

Timothy W. Walsh of McDermott Will & Emery LLP, counsel to Furie, said that the deal broke down in part over disagreements among the company's creditors.

One creditor's request for a side letter on what might happen in the context of a Chapter 7 may also have held up the deal.

"Those discussions on that side letter broke down and haven't restarted," said Abhilash M. Raval of Milbank LLP, counsel to Melody Capital Partners, LP and Kachemak Exploration LLC.

Ravel alluded to cost overruns as another snag in the sale.

"Given the cost overruns that were happening, it seemed prudent to terminate the transaction last week," Raval said.

No details of the "liquidity issues" facing the business were given in court, but a source told Petroleum News that operating costs of the assets have "skyrocketed" under Furie's interim management, Ankura Consulting Group LLC.

Kachemak and Melody are exploring alternative sale prospects with the debtors and affiliates of term lender Energy Capital Partners and ING Capital LLC, Walsh said.

The parties will attempt to complete an agreement in time for a scheduled May 4 confirmation hearing, Walsh said.

On March 4 in Anchorage, the Alaska Industrial Development and Export Authority board unanimously approved a resolution authorizing an AIDEA loan of up to $7.5 million for Anchorage based HEX LLC to buy Furie's Cook Inlet assets.

"The loan to HEX is in support of the company's bid to acquire the Kitchen Lights offshore unit and related infrastructure out of bankruptcy from Furie Operating Alaska LLC," AIDEA told Petroleum News in a March 6 email.

The sale would be structured as an acquisition of the limited liability companies (Cornucopia Oil & Gas Co. LLC and Corsair Oil & Gas LLC) that own the natural gas leases and the natural gas production infrastructure of the Kitchen Lights unit located in Cook Inlet, Alaska, AIDEA said in the resolution.

—STEVE SUTHERLIN

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INTERNATIONAL

Saudi Arabia to slash spending by 5%

Saudi Arabia said the government will cut spending by 5%, or about $13.3 billion, to offset the impact of plunging oil prices and the effects of the new coronavirus on its economic outlook and deficit.

In a statement carried by the state-run Saudi Press Agency March 18, Finance Minister Mohammad Al-Jadaan said additional measures would be taken to deal with the drop in oil prices, but he did not elaborate further.

Saudi Arabia has around $500 billion in foreign reserves, but with oil prices plummeting to around $26 a barrel and tourism revenue drying up due to a suspension of the Muslim pilgrimage to Mecca, it was expected the kingdom would make cuts to its spending. Oil prices plunged as Saudis moved to flood the market and dominate sales amid a slowdown in demand for oil worldwide.

Saudi Crown Prince Mohammed bin Salman has been racing to diversify the economy away from reliance on oil for revenue. Despite broad efforts at transforming the economy, the country continues to rely on higher oil prices of around $80 a barrel to balance its budget. Al-Jaadan said the government approved a partial reduction in spending in areas "with the least social and economic impact."

He did not give specific details on where the spending cuts would happen.

Saudi Arabia has already announced a roughly $13 billion stimulus package to support the private sector and extend financing to small and medium-sized businesses impacted by the virus, which has affected countries around the world.

The kingdom has halted all commercial flights and closed its borders to travelers to slow down the spread of the virus, which has infected nearly 240 people in the country.

—ASSOCIATED PRESS

Petroleum news — Oil Patch Bits

Five board members elected at Doyon annual meeting

Doyon Ltd. announced March 20 that at its annual meeting of shareholders, five shareholders were elected to the board of directors. Incumbents Georgianna Lincoln, Shirley Cleaver, Orie G. Williams were joined by new board members, Marvin Roberts and Cheryl Cadzow. Each seat has a three-year term, ending in March 2023.

The board members join continuing directors Walter "Wally" Carlo, Jennifer Fate, Erica L. Frankson, Betty Huntington, Jerry Isaac, Sonta Hamilton Roach, Miranda Wright and Christopher Simon. The main item of business was the election of the five board members.

This year's annual meeting was historic, held virtually online in order to protect shareholders from the spread of COVID-19. Shareholders and proxyholders were able to vote their proxies by paper, electronically and by phone. Many agenda items were cancelled and will be rescheduled. Only the board election, president's report, and treasurers report were included on the agenda.

Doyon's quorum was announced at 59.85% and at least 562 shareholders logged in and participated via Doyon's live webcast of the virtual meeting. Doyon's board of directors also participated remotely.

Many components of the annual meeting, including the keynote addresses, shareholder question and comments, promotional giveaways and shareholder of the year awards will be rescheduled, hopefully in conjunction with sister organizations Tanana Chiefs Conference and Fairbanks Native Association.

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SB 123

makes changes to the statutes governing the operation of electrical and telecommunications cooperatives — the existing statutes date from 1959 and need updating to reflect the use of modern technologies and communication capabilities.

Fragmented grid management

The Railbelt electrical system, which runs from the southern Kenai Peninsula through Southcentral Alaskan north to the Fairbanks region, is owned and operated by six independent electric utilities and the State of Alaska. And, while the utilities have achieved a high level of reliability in supplying electricity to their customers, there are significant concerns regarding the need for a more coordinated approach to the provision and maintenance of generation and transmission facilities across the system, and for open access to the system for independent power producers. There are also concerns relating to the need for a consistent set of mandated reliability standards, including standards for cybersecurity and physical security.

RRC agreement

In December all six of the Railbelt utilities signed a memorandum of understanding for the formation of the Railbelt Reliability Council, in effect an electric reliability organization for the Railbelt. The RRC will maintain and mandate reliability standards; administer rules for open access to the grid; conduct Railbelt-wide system planning; and investigate the economic value of security constrained economic dispatch for all or part of the system. Economic dispatch involves the continuous use of the most cost effective power generation that is securely available.

But the RRC also requires RCA regulation and oversight, something that is not possible under current statutes defining how the RCA can operate. Hence part of the urgency to pass SB 123, to enable the implementation of the RRC to proceed this year.

Started in 2014

The passage of SB 123 and the initiative to form the RRC are outcomes of a process that started in 2014, when the Legislature directed the RCA to investigate the manner in which the Railbelt electrical system was operated. Although covering a large geographical area, the Railbelt grid is small in terms of its electrical load and generation capacity. But the evolution of the system through its fragmented ownership has resulted in inefficiencies. There has been a lack of coordination in the development of new generation capacity, for example. The pancaking of electricity transmission fees across sectors of the grid owned by different entities elevates transmission costs. The business economics of making major upgrades to the transmission system are very challenging. And it is difficult for independent power producers, including purveyors of renewable energy, to connect to the system.

2015 report

In 2015 the RCA responded to the Legislature by submitting a report, recommending various changes to the management of the system. The commission recommended the implementation of merit-ordered economic dispatch; the formation of a single transmission company, to operate the transmission grid; and the implementation of a single set of enforced reliability standards. The commission also opened a docket to investigate the formation of some form of unified operator, to oversee the management of the entire electrical system.

Since then the commission has been encouraging voluntary efforts by the utilities to follow the commission's recommendations.

The utilities had been making significant progress towards the implementation of economic dispatch, especially in Southcentral Alaska. However, the initiatives for achieving this were placed on hold, pending the proposed purchase of Anchorage based Municipal Light & Power by Chugach Electric Association.

In April 2018 the utilities filed an agreed set of reliability standards and have since added cybersecurity standards. Maintenance and enforcement of these standards would become a function of the RRC, with regulatory oversight by the RCA, enabled by the passage of SB 123.

In March 2019 four of the utilities and the American Transmission Co. filed an application for RCA certification of a transmission company. However, this application was withdrawn later in the year following objections from some utilities about the manner in which the proposed transco was structured and would operate. Key concerns included the governance of the proposed company, which would have operated as a for-profit corporation.

Some utilities expressed a view that the RRC should be formed first, to provide governance of the entire system. GDS Associates, the consultancy involved in the development of the RRC concept, has since suggested that functional control of the transmission grid could at some stage be made an additional responsibility of the RRC. However, this issue has yet to be resolved.

Governance

Effective and balanced governance will be a critical factor in the success of future oversight of the electrical system. On the one hand, the utilities have considerable expertise in the technicalities and business of operating the system. On the other hand, there are other stakeholders, including independent power producers, consumers and the state, all of whom have significant interests in the system.

The RRC will be governed by a board with six members representing the six Railbelt utilities and six independent members representing other stakeholders. The RRC CEO would have a tie-breaking vote on board decisions. Independent members would consist of two representatives from independent power producers, one member representing consumer interests, a representative from the Alaska Energy Authority and two non-affiliated members. The RCA and the state's Regulatory Affairs and Public Advocacy Section would have non-voting board seats. ●

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WAITING GAME

tor, but nothing for the petroleum industry and, as of Petroleum News press time, no sign of when or if a larger financial package will be made available for what is the largest economic sector in Canada.

For now the bleeding continues as Canadian companies slash another C$4 billion in spending, a clawback that could cut oil production by 1.3 million barrels per day, or almost one-third of Canadian output.

All that has emerged from the national government has been a hint from Finance Minister Bill Morneau of a possible change to industry payroll taxes.

Alberta measures

Alberta Premier Jason Kenney has opted to announce his own measures in hopes of helping the energy sector bridge its way to a more significant federal program.

The Kenney administration has temporarily waived about C$113 million in annual fees collected by the Alberta Energy Regulator from the industry and extended oil and gas tenures from 2020 to 2021, giving upstream operators more time to raise capital.

Kenney also appointed an economic advisory panel, led by economist Jack Mintz and including former Canadian prime minister Stephen Harper to look at the province's medium- and long-term economic recovery after COVID-19.

While those small steps were being taken, word was trickling out from federal sources, including mention of a three-hour meeting between O'Regan and the Canadian Association of Petroleum Producers.

Those sources suggested federal aid could facilitate easier access to credit, especially for small- and medium-sized producers who are rapidly sinking below the surface as they get bled dry by the collapse in stock values and commodity prices.

Credit facility pushed

Meanwhile, Kenney has put pressure on the Trudeau administration introduce a credit facility similar to the U.S. Troubled Asset Relief Program, TARP, that saved banks and automobile manufacturers during the 2008-09 financial crisis.

The TARP program would see the federal government buy shares in distressed companies, along the lines of what Canada did for the auto industry in 2008.

To drive home their woes, 65 petroleum industry chief executive officers also asked the federal government to suspend plans to raise the federal carbon tax in C$10 annual increments from C$20 per metric ton to C$50 in 2022 and lower all income tax at every level, while urging banks to provide no-interest loans and loan guarantees.

What the critics don't want to see is a replay of TARP, whose money flowed to banks and wealthy shareholders.

Since the oil price crash in 2014, more than 50,000 direct jobs have been lost in Canada's oil patch and analysts doubt they will ever return, while companies have distributed massive dividends among their shareholders, reaching C$10.3 billion to shareholders in 2019 alone.

Bronwen Tucker, an Edmonton-based research analyst with Oil Change International, said trillions of dollars will be needed to build a resilient economy after the COVID-19 crisis, but "handing money over to oil and gas corporations will leave us more vulnerable."

She said the chance should be taken to "fund a just transition from oil and gas that protects workers, communities and the climate instead of tying their future to a sun-setting and volatile commodity."

Sector still reeling

Kenney has insisted that Trudeau "do no further harm" to the oil and gas sector which is reeling from a massive drop in revenues and is in no position to handle the planned increase in carbon taxes, or impose new limits on methane emissions that are rated as many times more potent than carbon dioxide.

The Alberta Energy Regulator says oil and gas operations are responsible for 70% of the province's methane emissions, but Kenney insists his government's own regulations to curb those emissions by 45% over the next five years are more effective than proposed new federal rules.

In addition, the Canadian government is sticking with a 2021 target for a ban on certain single-use plastics — a plan strongly opposed by major petrochemical companies that argue product demand should be market-driven and not mandated by government regulations.

The natural gas-derived plastics would be another blow to a sector that provides 7,500 direct jobs and has annual exports of C$8.2 billion.

In February Kenney told a business conference that a company he did not identify is planning a C$10 billion project that would create 10,000 permanent jobs.

Alberta's Natural Gas Minister Dale Nally said an aggressive federal attack on plastics would constitute an "unimaginable" overreach and flagrant attack on Alberta's economy. ●

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SOURDOUGH

Division Director Tom Stokes told Petroleum News March 23 that during the discussions with Jade the issue of low oil prices never came up. Rather, the drilling delay is due to scheduling challenges, such as barging in equipment and ice road construction, both of which can only be done during different specific and limited periods of time.

Working the issues

Jade initially submitted its second POD on Oct. 2, but on Nov. 29 Stokes granted an extension of the first POD until March 31 to give Jade and the division time to consider several issues related to the economic viability of the proposed project.

Initially, the division requested resubmittal of the second POD by Jan. 31, 2020, but in subsequent email correspondence between Jade and the division, the resubmittal date was extended to give them more time.

During this period, Jade also continued to work on permitting, which began this past summer.

On Feb. 29, Jade's exploration/appraisal program oil discharge prevention and contingency plan application package was deemed complete by the Alaska Department of Environmental Conservation.

Southeastern portion of Area F

Area F of the PTU was created by the terms of the Point Thomson Unit Settlement Agreement between PTU operator ExxonMobil and the other owners. Area F consists of 7,647 non-adjacent acres in the northeastern and southeastern corners of the PTU.

Jade became majority owner and operator of PTU Tract 32, ADL 343112, in the southeastern portion of Area F, by agreement with ExxonMobil Alaska Production Inc. in mid-2018.

Potential Brookian reservoirs have been encountered by numerous wells that have been drilled in and near the PTU since the 1970s. Sourdough 2 was drilled to a true vertical depth of 12,562 feet and was plugged and abandoned. Sourdough 3 was drilled to 12,425 feet TVD and was suspended.

In addition to the data derived from these wells, various 3D seismic surveys have been acquired and interpreted over Area F.

Jade acquired new compressive sensing imaging, or CSI, seismic 3D data from the area during the 2017-18 winter season with parameters optimized to characterize Brookian strata. The CSI 3D survey was the first of three field studies.

Dredging needed

In the first POD, Jade identified a series of 12 goals for 2019.

"Generally speaking, we fully or partially achieved 92% of the goals … while 8% of the targets were missed. The misses were largely the result of new information provided by the second field study conducted by Jade to support appraisal operations," the company said in its March 17 filing.

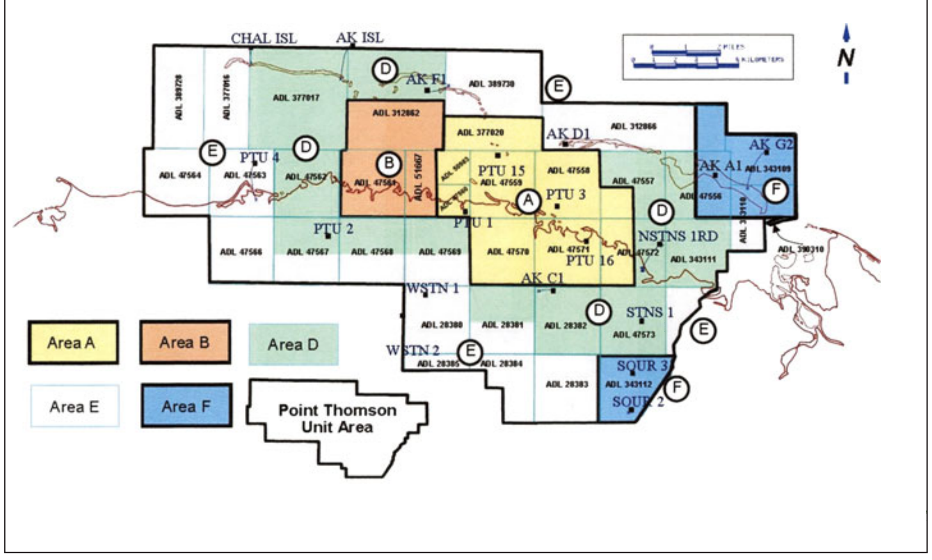
In that case, a Bathymetric survey of the PTU service pier approach showed that dredging of the sea-bottom would be required to land a barge carrying the drilling rig.

Not only was it too late in the 2019 summer season to organize and execute such a dredging operation, but the campaign would require Jade to obtain a federal permit from the U.S. Army Corps of Engineers, potentially a six-month exercise.

Based on its interpretation of area data, Jade planned to drill the Sourdough appraisal well in the winter 2020-21 drilling season utilizing existing PTU infrastructure to conduct its operations, supported by the construction of additional Jade infrastructure, such as an ice road. However, given the circumstances, Jade was unable to deliver on its goal of mobilizing a rig, equipment and materials to Point Thompson.

Therefore, in August Jade elected to delay its drilling program by one year — a delay that "has in no way diminished Jade's enthusiasm for the project and we continue moving forward on numerous fronts," the company said in its second POD filing.

Point Thomson Unit



JADE ENERGY

Third field study

In September Jade conducted its third field study to "evaluate suitability of the proposed Jade 1 drillsite," which included a helicopter survey of the ice road alignment between the PTU road system and the drill pad.

Jade launched a program designed to interface with state and North Slope Borough stakeholders that would ultimately deliver a full permit package for the proposed project.

The company's administrative goals and objectives for the second POD do "not differ dramatically" from those in the first POD.

Seismic data evaluation will continue in order to fully characterize the resource. Some of the work will focus on selecting additional delineation and development well locations particularly in any "expansion" areas that may be added to ADL 343112 resources through negotiations with the other PTU working interest owners, Jade said.

Well design, permitting and putting together third party agreements will also continue, including designing and permitting for drilling Jade 1 in the 2021-22 winter season.

Jade expects to submit its Sourdough Plan of Operations in second quarter, addressing its plans in detail.

Unique opportunity

The company's plans to mobilize a drilling rig to Point Thomson by barge from the Deadhorse area presents a "unique opportunity to capture significant savings versus what would typically be spent on a traditional ice road focused rig mobilization scenario," the company said.

"Capturing such savings is key to the economic viability of the project. However, given seasonality drivers, many important tasks are limited to being executed only during very specific calendar windows; barging requires open water, ice road construction requires -20°F temperatures and getting men and equipment to the Jade 1 drillsite requires both conditions," Jade said.

Summer 2020 activities

This summer Jade plans to continue its wellsite work and permitting, including developing detailed construction plans for the ice road and the Jade 1 drill pad. Additionally, it will move to secure necessary equipment and contract services required to buildout its infrastructure. One specific field task will be the August installation by helicopter of several satellite link enabled thermistor stations along the ice road alignment and drill pad that will report ground temperature at various depths and snow cover to assist in construction planning.

A second bathymetric survey of the PTU service pier approach will be conducted by survey contractor HDR to confirm conditions ahead of a summer 2020 Corps permitted dredging campaign. Alternatively, Jade may use Bell and Associates to run a similar survey from sea ice earlier in the year which would provide data ahead of breakup.

The dredging operation will follow later in the summer.

Winter 2021-22 drilling

The Jade 1 drilling campaign in the winter of 2021-22 will utilize a medium sized mono-body rig — either Nordic Rig 3 or a similar unit. Weighing approximately 2.7 million pounds Nordic Rig 3 is a significant barge load, but once landed the rig will move efficiently using existing infrastructure and newly constructed Jade ice roads and arrive ready to drill with little additional rig-up work, Jade said.

"With its own secondary containment, the rig presents and environmentally responsible package, particularly when underlaid by a Polystar berm system. The rig features a split pipe shed that allows casing to be run on one side and drill pipe run on the opposite side. Automated pipe handling equipment raises and lowers tubulars into either side of the pipe shed. Capable of standing back 16,000-feet of 4" drill pipe and hoisting 464,000 pounds the rig is ideal for medium depth appraisal well programs such as Jade 1," the company said in its March 17 filing.

Jade intends to drill a vertical 8½-inch borehole to approximately 12,750 feet. Drilling to that depth will penetrate "all of the prospective Brookian sand target that lay between 11,000 feet and the Hue Shale at ~ 12,500 feet while provide sufficient rathole to support subsequent wireline logging."

Formation evaluation will employ a combination of logging while drilling, or, LWD, and wireline logging, or WL, programs that will include the extraction of rotary sidewall cores, Jade said.

"Given the probability of success, Jade expects to run casing, perforate the zone or zones of interest, then flow back the well for 24-hours. Naturally the testing program details will be dependent on the formation characteristics of the section penetrated," the company said. ●

Division Director Tom Stokes told Petroleum News March 23 that during the discussions with Jade the issue of low oil prices never came up. Rather, the drilling delay is due to scheduling challenges, such as barging in equipment and ice road construction, both of which can only be done during different specific and limited periods of time.

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MATT SHOTENSKI, COURTESY OF CONOCOPHILLIPS ALASKA

One of seven Rig 26 modules as it is leaving Deadhorse on March 23.

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ERD RIG

The largest mobile land rig in North America and 1.5 to 2 times more powerful than other North Slope rigs, Doyon 26 is expected to increase Alaska oil production by accessing previously unreachable resources without expanding the surface footprint. Northwest of the main Alpine field, Fiord West is projected to produce 20,000 barrels of oil per day at its peak.

At ConocoPhillips' November analyst and investor meeting, Michael Hatfield, president, Alaska, Canada and Europe, said the ERD rig combines advanced drilling technologies, including managing "pressure drilling" and is equipped with the "latest in rig automation. It incorporates a reflective drilling system that can automate repetitive tasks and improve performance significantly. These technologies will enable us to manage the challenges of drilling even longer and more complex wells to access additional resources."

From CD2 pad, the giant ERD rig will target the Fiord West Kuparuk reservoir, which was discovered in 1996, but because it's in an environmentally sensitive area along the coast it couldn't be accessed.

Over the next 10 years, "we expect the ERD rig will access 100 million barrels at a constant supply of $25 a barrel," Hatfield said. "Our track record of execution has allowed us to economically develop these areas and will be key to continuing to unlock value in Alaska."

—KAY CASHMAN

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CONTINGENCY PLANS

must be consistent with the state/federal-managed Regional and Area Contingency Plans."

Alyeska Pipeline

Alyeska Pipeline Service Co. noted it holds multiple state-approved oil discharge prevention and contingency plans and said it encourages ADEC "to initiate the formal regulation drafting and review process for all of 18 AAC 75 Article 4 and Alaska Statute 46.04."

It said: "periodic review of contingency planning regulatory requirements is a valuable step in ensuring that the regulations and statutes remain relevant, comprehensive, transparent, and encourage state-of-the-art capability."

The company said a 2016 regulation amendment "allowed for the State to host industry ODPCPs on the ADEC website," which eliminated "expensive and time-consuming hard copy production and distribution" and made "the plans accessible and transparent to a wider audience."

Alyeska created an internal work group which coordinated with industry peers on issues of joint interest and the company submitted "a representative sampling of both major issues and minor recommendations as sufficient evidence to support a formal public review of the statute and regulation."

Local governments

ADEC received resolutions opposing changes from a number of local governments.

That from the City of Seldovia is representative: "the City Council of the City of Seldovia strongly opposes legislative or regulatory changes that erode oil spill prevention and response standards, increase the risk of a catastrophic spill, or demonstrate a return of the complacency on the part of the oil industry and regulators that Congress determined to be a primary cause of the Exxon Valdez oil spill."

The City of Valdez said: "The Valdez City Council strongly opposes any legislative or regulatory changes that erode oil spill prevention and response standards, reduce opportunities for public input and review, increase the risk of a catastrophic oil spill, or demonstrate complacency on the part of the oil industry and regulators."

The resolutions were in line with numerous individual comments, which said ADEC should not weaken the state's defense against oil spills.

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