Petroleum news

page 6 DOG transfers Mustang control to Finnex retro to Nov. 1

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Jade seeks Sourdough reset; files reconsideration request

1 2 SERIES

ERIK OPSTAD

On March 1, Jade Energy sent John Boyle. commissioner of the Alaska Department of Natural Resources, by certified mail a "Request for Reconsideration of Commissioner Decision Relayed in Point Thomson Area F 2024 6th POD — Held in Abeyance." (That decision was made on Feb. 24.)

The request for reconsideration is a step in a process that must be followed before Jade can sue DNR in Alaska Superior Court. Erik Opstad, Jade managing member, has not publicly said whether court is his next step.

Another option for the independent is to walk away and take an estimated $20 million loss without recompense.

see **SOURDOUGH RESET** page 11

City of Unalaska exits Makushin geothermal, ends power agreement

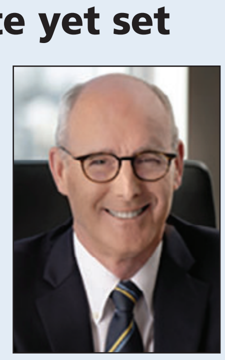
During its monthly meeting on Feb. 27 the Unalaska City Council allowed the expiry of a power purchase agreement with Ounalashka Chena Power LLC, or OCCP, for the purchase of electricity from a planned geothermal power plant on the flank of the Makushin volcano on Unalaska Island in the Aleutians. The decision leaves OCCP, developer of the project, without a customer for electricity from the geothermal system. And, with the company already experiencing difficulty in securing sufficient investment and grant funding to complete the project, the Unalaska city decision has presumably brought the project to a halt.

PPA modification

In early November OCCP requested a modification to the PPA that would increase the price of the electricity from the planned power plant from 16 cents per kilowatt hour to 22 cents per kilowatt hour. During a Nov. 28 Unalaska council meeting David Matthews, OCCP program manager for the Makushin project, commented that the electricity rate in the PPA was associated with the price of diesel fuel and that the

see **POWER AGREEMENT** page 10

Alberta revenues from TMX look good; no in-service date yet set



DEREK EVANS

The number crunching for Canada's Trans Mountain pipeline expansion, TMX, is now in full swing with the new pipeline connection of 890,000 barrels per day from the Alberta oil sands to Vancouver's tanker terminal expected to generate C$40 billion in royalties and taxes over two decades, more than covering the C$31 billion price tag of the expansion project.

So far, so good for Alberta.

Although the TMX owner — the Canadian government — has yet to set an in-service date for TMX, the company has served notice to producers to start moving crude into Trans Mountain.

"TMX has issued a call for line-fill … as a matter of fact they are looking for 2.1 million barrels per day in April and another 2.1 million bpd in May," said Derek Evans, chief

see **TMX NUMBERS** page 8

EXPLORATION & PRODUCTION

Excited but cautious

APA views exploration drilling on E. North Slope as risky but high reward

By KAY CASHMAN
Petroleum News

When asked to provide more color on the risk profile for the exploration drilling program APA Corp. is participating in this winter on Alaska's eastern North Slope, the company's CEO and President John J. Christmann said, "these are 3D and amplitude supported but this is a step-out in an area where there is risk associated with it so I'm not going to give you a number on a ratio. … We're going to drill three wells and they are risky but they're high reward."

APA is the holding company for Apache Corp. Its partners in the venture are operator Bill Armstrong's Lagniappe Alaska and Santos' Oil Search (Alaska), both of which hold a 25% working interest ownership in the 148-lease block on 275,000 acres being explored. APA holds a 50% working interest.

"What interested us in the block was that we do see materiality with these prospects that warranted exploration." —Tracy Henderson

Christmann was participating in a Feb. 22 conference call covering fourth quarter and full year 2023 financial and operational results.

He asked Tracy Henderson, the company's

see **APA DRILLING** page 10

ALTERNATIVE ENERGY

What about using coal?

Study recommends coal-biomass plant with CCS for low-cost Southcentral power

By KRISTEN NELSON
Petroleum News

A new coal- and biomass-fired power plant, coupled with carbon capture and storage, CCS, may provide the cheapest, lowest carbon and longest lasting answer to the problem of providing future electrical power to Southcentral Alaska as Cook Inlet's natural gas supply is depleted.

This was the conclusion of studies that Frank Paskvan, with the University of Alaska Fairbanks' Institute of Northern Engineering, reviewed for the House Special Committee on Energy March 5.

One, by the Alaska CCUS Workshop, published as SPE Paper 213051 last year ("Alaska CCUS Workgroup and a Roadmap to Commercial Deployment") focuses on carbon capture, utilization and storage, and a second, released Feb. 28, a joint project of UAF-INE and the Energy & Environmental Research Center at the University of North Dakota, focuses on the potential of low-carbon

The study also found that biomass-coal energy supply with CCS is lower cost than natural gas generated energy, with or without CCS, "and biomass-coal energy supply with CCS provides lower CO2 emissions than the current natural gas energy supply without CCS."

see **WHAT ABOUT COAL?** page 12

FINANCE & ECONOMY

ANS tests mid-$80s

A March 1 breakout fades, but ANS recovers for a mere 5-cent weekly loss

By STEVE SUTHERLIN
Petroleum News

ANS held its own in the $80s on the trading week ending Wednesday March 6, slipping just 5 cents over the week as it gained 84 cents on the day to close at $82.34 per barrel. West Texas Intermediate gained 98 cents to close at $79.13 and Brent gained 92 cents to close at $82.96.

The Alaska benchmark tested the mid $80s March 1, jumping $1.14 to close at $83.05. WTI leapt $1.71 to close at $79.97 and Brent slipped 7 cents to close at $83.55.

But all three benchmarks gave up ground on March 4 and March 5.

On March 4 ANS fell 75 cents to close at $82.30. WTI plunged $1.23 to close at $78.74 and Brent dropped 75 cents to close at $83.55.

On March 3, the Saudi Arabia Press Agency reported that Saudi Arabia will extend its voluntary crude production cut of 1 million barrels per day through end of second quarter 2024.

ANS dropped 80 cents March 5 to close at $81.51, while WTI shed 59 cents to close at $78.15 and Brent fell 76 cents to close at $82.04.

Red ink was the order of the day Feb. 29, as

see **OIL PRICES** page 9

● EXPLORATION & PRODUCTION

Hilcorp plans up to 6 new wells at Beluga

Latest plan of development for west side field shows 5 wells planned and drilled in previous POD to Sterling and Beluga gas sands

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska, operator of Beluga River on the west side of Cook Inlet, has filed a new plan of development and operations for the unit with the U.S. Bureau of Land Management, with up to six new wells planned for the upcoming POD period of April 1 through March 31, 2025, following completion of five new wells in the current POD period, April 1, 2023, through March 31, 2024.

The company apparently plans to continue drilling new wells in 2025, as it said its 2024 plans include evaluating pads for expansion to support the 2025 drilling program.

Hilcorp operates Beluga on behalf of itself and majority working interest owner Chugach Electric Association. The unit contains both federal and state acreage, onshore and offshore, and is produced from onshore pads.

Beluga is one of Cook Inlet's most prolific natural gas producers, and the largest on the west side.

Alaska Oil and Gas Conservation Commission production data for January show recent increases in production: the field averaged 41,365 thousand cubic feet of gas per day, up 8.7% from a January 2023 average of 38,050 mcf per day. That volume was an 11.9% increase from a January 2022 average of 34,011 mcf per day.

The company said cumulative production from Beluga River during calendar year 2023 was 13.44 billion standard cubic feet.

Completed under 2023 POD

Under the 2023 POD, Hilcorp planned up to five wells using Rig 147 and targeting Sterling and Beluga gas sands. All five grassroots wells were completed, with initial rates ranging from 3.2 million cubic feet per day to 4.5 million cubic feet per day.

Hilcorp's workover program included installing a velocity string and five workovers adding perforations and e-line work, with an additional workover planned for March.

Facilities work included moving a compressor from C Pad to K Pad and installing facilities at DW-02 Pae to allow disposal of drill cuttings and drilling mud into a disposal well.

The company said cumulative production from Beluga River during calendar year 2023 was 13.44 billion standard cubic feet.

2024 POD

In the 2024 POD, Hilcorp plans up to six grassroots/sidetrack wells with Rig 147, the company said, each targeting Sterling and Beluga gas sands.

The workover program planned includes "several uphole recompletes, perforation adds and rig workovers to existing wells to help maintain and increase production," the company said, with projects which may include coil cleanout operations and adding or isolating Sterling or Beluga gas perforations.

Facility projects, in addition to routine repairs and replacement work as needed, include restaging the H Pad compressor to increase flow rate; flowline, separator and production header work at G, H and J pads to support 2024 drilling; replacing the Phase II reboiler at H Pad; and evaluating and executing pad expansion for the 2025 drilling campaign, with expansions currently being considered at D, F and I pads, with locations subject to change. ●

Contact Kristen Nelson at knelson@petroleumnews.com

contents

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● EXPLORATION & PRODUCTION

Baker Hughes US rig count up by 3 to 629

February international rig count, which excludes North America, down 7 from January at 958, with land rigs down by 5, offshore 2

By KRISTEN NELSON
Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 629 for the week ending March 1, up by three rigs from 626 the previous week, but down by 120 from 749 a year ago. The rig count increased in five of the last eight weeks and decreased in three, with a gain of 14 against a loss of six over the period, bucking a downward trend dominant since the beginning of May.

A drop of 17 to 731 on May 12, 2023, was the steepest weekly drop since June of 2020, during the first year of the COVID-19 pandemic, when the count also dropped by 17 to 284 on June 5, following drops as steep as 73 rigs in one week in April. The count continued down to 251 at the end of July 2020, reaching an all-time low of 244 in mid-August 2020.

For 2023, the count hit its low point Nov. 10 at 616, down from a high of 775 on Jan. 13, 2023. In 2022, the count bottomed out at 588 Jan. 1, reaching a high for the year of 784 on Nov. 23.

When the count dropped to 244 in mid-August 2020, it was the lowest the domestic rotary rig count had been since the Houston based oilfield services company began issuing weekly U.S. numbers in 1944.

Prior to 2020, the low was 404 rigs in May 2016. The count peaked at 4,530 in 1981.

The count was in the low 790s at the beginning of 2020 prior to the COVID-19 pandemic, where it remained through mid-March of that year when it began to fall, dropping below what had been the historic low in early May with a count of 374 and continuing to drop through the third week of August 2020 when it gained back 10 rigs.

The March 1 count includes 506 rigs targeting oil, up by three from the previous week and down 86 from 592 a year ago, with 119 rigs targeting natural gas, down by one from the previous week and down 35 from 154 a year ago, and four miscellaneous rigs, up by one from the previous week and up one from a year ago.

Fifty-two of the rigs reported March 1 were drilling directional wells, 561 were drilling horizontal wells and 16 were drilling vertical wells.

The Alaska (13) rig count was up by two from the previous week.

New Mexico (103), Oklahoma (45) and West Virginia (8) were each up by a single rig.

Texas (299) was down by two rigs.

Rig counts in other states were unchanged from the previous week: California (6), Colorado (16), Kansas (1), Louisiana (45), North Dakota (32), Ohio (12), Pennsylvania (24), Utah (12) and Wyoming (11).

Baker Hughes shows Alaska with 13 rotary rigs active March 1, up by two from the previous week and up by six from a year ago when the count was seven. Twelve of the Alaska rigs were onshore, up by two from the previous week, with one rig working offshore, unchanged from the previous week.

The rig count in the Permian, the most active basin in the country, was up by one from the previous week at 315 and down by 34 from 349 a year ago.

Baker Hughes' monthly international rig count for February, issued March 1, is down by seven from January at 958, with land rigs down five to 735 and the offshore count at 223 down by two. Compared to the February 2023 count of 915, the February 2024 international count is up by 43, with land rigs up by 42 and offshore rigs up by one.

Baker Hughes began providing a monthly international rig count in 1975. The international count excludes North America, which is included in the company's worldwide figures.

The Middle East accounted for the most rigs in the international totals for February, 349, followed by Asia Pacific with 219, Latin America with 165, Europe with 114 and Africa with 111.

The U.S. rig count averaged 623 in February, up by two from January, and down 135 from February 2023, while the Canadian count for February averaged 232, up 35 rigs from January and down by 18 from February 2023.

Worldwide the rig count was 1,813 in February, up 30 from 1,784 in January and down 108 from 1,921 in February 2023. ●

Contact Kristen Nelson at knelson@petroleumnews.com

CANADA

Trans Canada Energy sells PNGTS

Trans Canada Energy, Canada's second-largest oil and natural gas carrier, has demonstrated its steadfast commitment to complete C$3 billion of asset sales this year by unloading its Portland Natural Gas Transmission system for US$ 1.14 billion.

In taking a big step towards its 2024 goals of trimming its balance sheet, Calgary-based TC Energy announced March 4 its sale of Portland Natural Gas is a "unique opportunity to support our capital commitments and deleverage priorities while continuing to meet the needs of the communities PNGTS serves."

PNGTS is a 475-kilometer gas pipeline system that serves upper New England and Atlantic Canada markets and receives natural gas from the Trans Quebec and Maritimes pipeline via the Canadian Mainline.

The Portland sale is expected to close in mid-2024 subject to regulatory approvals and customary closing conditions.

TC Energy sold a 40% stake in its Columbia Gas and Columbia Gulf systems to New York-based Global Infrastructure Partners last year for US$5.3 billion.

TC Energy has been seeking to sell assets in order to pay off debt at a time when it is under significant scrutiny from investors and credit rating agencies for its heavy debt load, as well as for the spiraling cost of the 670-kilometer Coastal Gas Link pipeline it completed last fall in British Columbia after the budget ballooned to C$11.2 billion from C$6.2 billion.

—GARY PARK

UTILITIES

GVEA modifies power generation strategy

Fairbanks based Golden Valley Electric Association has modified its strategy for meeting its future power generation needs, in recognition of recent changes in the outlook for energy sources in the region. The changes in outlook include the availability of federal grant funding opportunities and the unavailability of reliable, lower cost energy sources to replace power from the utility's Healy Unit 2 coal fired power station, the utility says.

The changes in outlook include the availability of federal grant funding opportunities and the unavailability of reliable, lower cost energy sources to replace power from the utility's Healy Unit 2 coal fired power station, the utility says.

In June 2022 the utility adopted a new strategy for power generation. That strategy consisted essentially of upgrading the utility's Healy Unit 1 coal fired power station, the retirement of Healy Unit 2; a request for proposal for a large-scale wind power facility; the installation of a new battery energy storage system; and the securing of a power purchase agreement for natural gas fueled power generation.

The new modifications to the strategy consist of completing the installation of a selective catalytic reduction system on Healy Unit 1; the continued operation of Healy Unit 2 until alternative sources of reliable, lower cost energy become available; finalizing negotiations for integrating large-scale wind resources into GVEA's system at a price that will reduce power costs for GVEA members; installing energy storage with sufficient capacity to enable the integration of large-scale renewable resources; and continuing with efforts to secure reliable, base load generation that can replace the use of Healy Unit 2.

On March 1 the utility announced an increase to its electricity rates primarily as a result of a prolonged outage at Healy Unit 2 and the high price of fuel oil. All of the Railbelt utilities are facing issues relating to questions over the future availability and cost of Cook Inlet natural gas for power generation. GVEA purchases some power from Southcentral utilities that use gas-fueled power generation plants.

—ALAN BAILEY

● EXPLORATION & PRODUCTION

ANS production down 1.4% from December

January average 476,119 bpd; increases at Greater Mooses Tooth, Colville River; decreases at Kuparuk, Point Thomson, Milne Point

By KRISTEN NELSON

Petroleum News

Alaska North Slope production averaged 476,119 barrels per day in January, down 6,540 bpd, 1.4%, from a December average of 482,659 bpd and down 4.9% from a January 2023 average of 500,747 bpd. Crude averaged 417,998 bpd, 87.8% of the total, down 5,971 bpd, 1.4%, from a December average of 423,969 bpd and down 4.9% from a January 2023 average of 439,735 bpd. Natural gas liquids averaged 58,121 bpd in January, 12.2% of the total, down 569 bpd, 1%, from a December average of 58,691 bpd and down 4.7% from a January 2023 average of 61,012 bpd.

Production data come from the Alaska Oil and Gas Conservation Commission which reports production by field and well on a month delay basis.

Temperature data from the county time series maintained by NOAA's National Centers for Environmental Information, which has North Slope Borough temperatures beginning in 1925, show an average temperature for the NSB of -8.3 degrees F for January, compared to -4.1 degrees F in December, and 5 degrees warmer than the 1925-2000 mean temperature for January of -13.3 degrees.

Month-over-month increases

The largest month-over-month production increase was at ConocoPhillips Alaska's Greater Mooses Tooth unit in the National Petroleum Reserve-Alaska, which averaged 15,922 bpd in January, up 1,750 bpd, 12.4%, from a December average of 14,172 bpd but down 5.6% from a January 2023 average of 16,866 bpd. The majority of GMT production is from the Rendezvous oil pool, 88% in January. Eight wells were in production from that pool in January compared to seven in December.

ConocoPhillips's Colville River unit averaged 34,464 bpd in January, up 903 bpd, 2.7%, from a December average of 33,561, but down 3.8% from a January 2023 average of 35,806 bpd. In addition to oil from the main Alpine pool, Colville includes production from the Nanuq and Qannik oil pools.

There was also a small month-over-month increase at the Hilcorp Alaska-operated Endicott field, which averaged 6,217 bpd, up 35 bpd, 0.6%, from a December average of 6,182 bpd, but down 6% from a January 2023 average of 6,613 bpd. Crude production at Endicott averaged 5,364 bpd in January, 86.3% of the total, down 19 bpd, 0.4%, from a December average of 5,383 bpd and down 8% from a January 2023 average of 5,831 bpd. Endicott NGL production averaged 854 bpd in January, 13.7% of the total, up 55 bpd, 6.8%, from a December average of 799 bpd and up 9.2% from a January 2023 average of 782 bpd.

Month-over-month decreases

The largest month-over-month decrease was at the ConocoPhillips-operated Kuparuk River unit, which averaged 76,638 bpd in January, down 2,978 bpd, 3.7%, from a December average of 79,616 bpd and down 7.1% from a January 2023 average of 82,511 bpd. In addition to the main Kuparuk pool, Kuparuk produces from satellites at Tabasco and Tarn, and from West Sak.

Production from the Hilcorp North Slope-operated Prudhoe Bay unit averaged 273,269 bpd in January, down 1,975 bpd, 0.7%, from a December average of 275,245 bpd and down 3% from a January 2023 average of 281,681 bpd. Crude production at Prudhoe, 80% of the total, averaged 218,527 bpd in January, down 1,539 bpd, 0.7%, from a December average of 220,067 bpd and down 2.7% from a January 2023 average of 224,633 bpd. Prudhoe NGLs averaged 54,742 bpd in January, 20% of the total, down 436 bpd, 0.8%, from a December average of 55,178 bpd and down 4.1% from a January 2023 average of 57,048 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.

Production from the Hilcorp Alaska-operated Point Thomson field averaged 1,790 bpd in January, down 1,965 bpd, 52.3%, from a December average of 3,754 bpd and down 75.4% from a January 2023 average of 7,288 bpd. AOGCC data show the field only produced for 14 days in January, this after discovery of a leak in the line taking liquids to an interconnection with the pipeline from Badami. The Alaska Department of Environmental Conservation's Division of Spill Prevention said Feb. 2 in its final situation report on the leak that a repair claim was installed on the line Jan. 28.

Hilcorp Alaska's Milne Point averaged 41,077 bpd in January, down 1,308 bpd, 3.1%, from a December average of 42,385 bpd but up 5% from a January 2023 average of 39,114 bpd. Milne Point produces primarily from the Schrader Bluff and Kuparuk oil pools, with minor Sag River and Ugnu volumes.

Eni's Oooguruk averaged 5,859 bpd in January, down 358 bpd, 5.8%, from a December total of 6,217 bpd and down 10.6% from a January 2023 average of 6,553 bpd.

Eni's Nikaitchuq averaged 14,319 bpd in January, down 338 bpd, 2.3%, from a December average of 14,656 bpd and down 15.2% from a January 2023 average of 16,889 bpd.

Hilcorp Alaska's Northstar averaged 5,698 bpd in January, down 273 bpd, 4.6%, from a December average of 5,971

see ANS OUTPUT page 5

Cook Inlet gas production up 1.7%

Natural gas production in Cook Inlet averaged 216,685 thousand cubic feet per day in January, up 3,661 mcf per day, 1.7%, from a December average of 213,023 mcf per day but down 3.8% from a January 2023 average of 225,202 mcf per day.

Volumes are calculated from Alaska Oil and Gas Conservation Commission data, reported on a month-delay basis. For natural gas AOGCC reports measurements in thousands of cubic feet, mcf.

Twenty fields produced natural gas in January, with seven — each with 5% or more of the total — accounting for a combined 85.9% of inlet production for the month.

Hilcorp Alaska's North Cook Inlet averaged 46,443 mcf per day in January, 21.4% of the inlet total, up 5,534 mcf per day, 13.5%, from a December average of 40,910 mcf per day and up 19.4% from a January 2023 average of 38,886 mcf per day.

Hilcorp's Ninilchik averaged 42,667 mcf per day in January, 19.7% of the inlet total, down 4,656 mcf per day, 9.8%, from a December average of 47,322 mcf per day and down 14.9% from a January 2023 total of 50,155 mcf per day.

Hilcorp-operated Beluga River averaged 41,364 mcf per day in January, down 653 mcf per day, 1.6%, from a December average of 42,017 mcf per day, but up 8.7% from a January 2023 average of 38,050 mcf per day.

Hilcorp's Kenai field averaged 18,986 mcf per day in January, 8.8% of the inlet total, down 425 mcf per day, 2.2%, from a December average of 19,411 mcf per day and down 17.7% from a January 2023 average of 23,079 mcf per day.

Hilcorp's McArthur River averaged 12,976 mcf per day in January, 6% of the inlet total, down 133 mcf per day, 1%, from a December average of 13,109 mcf per day and down 17.2% from a January 2023 average of 15,672 mcf per day.

Furie's Kitchen Lights averaged 12,537 mcf per day in January, 5.8% of the inlet total, up 2,075 mcf per day, 19.8%, from a December average of 10,463 mcf per day and up 2.9% from a January 2023 average of 12,181 mcf per day.

Hilcorp's Beaver Creek averaged 11,103 mcf per day in January, 5.1% of the inlet total, up 1,108 mcf per day, 11.1%, from a December average of 9,995 mcf per day

see INLET GAS page 5

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ANS OUTPUT

bpd and down 17.7% from a January 2023 average of 6,924 bpd. Northstar crude averaged 3,172 bpd in January, 55.7% of the total, down 85 bpd, 2.6%, from a December average of 3,257 bpd and down 15.2% from a January 2023 average of 3,741 bpd. Northstar NGLs averaged 2,526 bpd in January, 44.3% of the total, down 188 bpd, 6.9%, from a December average of 2,714 bpd and down 20.6% from a January 2023 average of 3,182 bpd.

Savant Alaska's Badami averaged 867 bpd in January, down 33 bpd, 3.7%, from a December average of 900 bpd but up 72.4% from a January 2023 average of 503 bpd. The year-over-year increase comes primarily from the undefined oil pool, which produced from one well in January 2023 (B1-38) and from two wells this January (B1-07 and B1-38), accounting for 51% of Badami production, compared to 26.5% in January 2023, and this year accounting for more than three times the oil it contributed in January 2023.

Cook Inlet crude down 5%

Production in Cook Inlet averaged 8,594 bpd in January (99.3% crude and 0.7% NGLs), down 453 bpd, 5%, compared to a December average of 9,047 bpd and down 1.9% from a January 2023 average of 8,762 bpd.

Hilcorp Alaska's Beaver Creek averaged 289 bpd in January, down 11 bpd, 3.6%, from a December average of 299 bpd and down 43.1% from a January 2023 average of 507 bpd.

Hilcorp's Granite Point averaged 2,136 bpd in January, up 5 bpd, 0.3%, from a December average of 2,131 bpd but down 6.1% from a January 2023 average of 2,274 bpd.

BlueCrest's Hansen averaged 669 bpd in January, down 27 bpd, 3.9%, from a December average of 697 bpd and down 9.1% from a January 2023 average of 736 bpd.

Hilcorp's McArthur River averaged 2,457 bpd in January, down 120 bpd, 4.7%, from a January average of 2,577 bpd and down 14.6% from a January 2023 average of 2,879 bpd.

Cook Inlet Energy's Redoubt Shoal averaged 472 bpd in January, down 49 bpd, 9.4%, from a December average of 522 bpd but up 3.3% from a January 2023 average of 457 bpd. CIE is a Glacier Oil and Gas company.

Hilcorp's Swanson River averaged 822 bpd in January, up 35 bpd, 4.4%, from a December average of 787 bpd and up 13.2% from a January 2023 average of 726 bpd. Swanson production was 92.6% crude in January and 7.4% NGLs.

Hilcorp's Trading Bay averaged 881 bpd in January, down 17 bpd, 1.9%, from a December average of 898 bpd but up 7.2% from a January 2023 average of 822 bpd.

CIE's West McArthur River averaged 867 bpd in January, down 269 bpd, 23.7%, from a December average of 1,136 bpd but up 140.9% from a January 2023 average of 360 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

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INLET GAS

and up 24.1% from a January 2023 average of 8,950 mcf per day.

Fields with less natural gas production accounted for less than 15% of inlet production in January.

Hilcorp's Swanson River averaged 6,859 mcf per day in January, up 1,219 mcf per day, 21.6%, from a December average of 5,641, but down 18.8% from a January 2023 average of 8,447 mcf per day.

Hilcorp's Cannery Loop averaged 5,272 mcf per day in January, up 141 mcf per day, 2.7%, from a December average of 5,131 mcf per day but down 17.7% from a January 2023 average of 6,408 mcf per day.

Hilcorp's Deep Creek averaged 3,537 mcf per day in January, up 59 mcf per day, 1.7%, from a December average of 3,478 mcf per day, but down 14.1% from a January 2023 average of 4,117 mcf per day.

Hilcorp's Granite Point averaged 3,092 mcf per day in January, down 17 mcf per day, 0.6%, from a December average of 3,109 mcf per day and down 7% from a January 2023 average of 3,325 mcf per day.

Hilcorp's Ivan River averaged 2,720 mcf per day in January, down 522 mcf per day, 16.1%, from a December average of 3,242 mcf per day and down 60.8% from a January 2023 average of 6,937 mcf per day.

AIX's Kenai Loop averaged 2,221 mcf per day in January, down 45 mcf per day, 2%, from a December average of 2,266 mcf per day and down 8% from a January 2023 average of 2,415 mcf per day.

Vision Operating's North Fork averaged 2,008 mcf per day in January, down 44 mcf per day, 2.1%, from a December average of 2,052 mcf per day and down 32.5% from a January 2023 average of 2,977 mcf per day.

Hilcorp's Lewis River averaged 1,803 mcf per day in January, up 82 mcf per day, 4.7%, from a December average of 1,721 mcf per day and up 382% from a January 2023 average of 374 mcf per day.

BlueCrest's Hansen averaged 1,301 mcf per day in January, up 97 mcf per day, 8.1%, from a December average of 1,203 mcf per day but down 18.8% from a January 2023 average of 1,602 mcf per day.

Hilcorp's Trading Bay averaged 1,041 mcf per day in January, down 6 mcf per day, 0.6%, from a December average of 1,047 mcf per day but up 2.3% from a January 2023 average of 1,018 mcf per day.

Cook Inlet Energy's West McArthur River averaged 238 mcf per day in January, down 14 mcf per day, 5.5%, from a December average of 252 mcf per day but up 142.6% from a January 2023 average of 98 mcf per day. CIE is a Glacier Oil and Gas company.

Hilcorp's Nikolaevsk averaged 201 mcf per day in January, down 33 mcf per day, 14.1%, from a December average of 235 mcf per day and down 9.9% from a January 2023 average of 224 mcf per day.

CIE's Redoubt Shoal averaged 171 mcf per day in January, up 36 mcf per day, 26.3%, from a December average of 135 mcf per day and up 31.8% from a January 2023 average of 130 mcf per day.

Amaroq's Nicolai Creek averaged 144 mcf per day in January, down 140 mcf per day, 49.4%, from a December average of 284 mcf per day and down 8.7% from a January 2023 average of 157 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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EXPLORATION & PRODUCTION

Change of control to Finnex approved

Alaska's Division of Oil and Gas transfers complete interest in Mustang Holding and MOCI from AIDEA to Finnex Operating

By KAY CASHMAN

Petroleum News

On Oct. 27, the Alaska Department of Natural Resources' Division of Oil and Gas received assignment applications under 11 AAC 82.605(f) transferring complete interest in Mustang Holding LLC, or Mustang, and Mustang Operations Center 1 LLC, or MOC1, from Alaska Industrial Development and Export Authority, or AIDEA, to Finnex Operating LLC for the following state of Alaska leases: ADLs 390680, 390681, 390690, 390691 and 39069.

The assignor and assignee represented the following to DNR:

•AIDEA currently owns 100% membership of Mustang;

•Mustang owns 100% membership of MOC1;

•Finnex is acquiring 100% membership from AIDEA;

•Mustang and MOC1 will remain the working interest owners of the leases listed above.

Any party holding an interest in an assigned lease may be required to enter into a financial assurances agreement in the future to ensure dismantlement, removal, and restoration obligations can be met.

Division of Oil and Gas Director Derek Nottingham approved change of control to Finnex on Feb. 29, with an effective date of Nov. 1, 2023.

Finnex advances plans

As reported in the Jan. 7 issue of Petroleum News, the operator of the South Miluveach unit, Mustang Holding, has an Oil Discharge Prevention and Contingency Plan under review by the Alaska Department of Environmental Conservation per a Dec. 27 ADEC notice. The proposed CPlan confirms that Mustang Holding and its new owner Finnex are moving forward with Finnex's plan to conduct a multi-year onshore oil and gas project year-round in the unit's Mustang field.

The Mustang Development targets the Kuparuk "C" sands, the same reservoir that is being produced in ConocoPhillips Alaska's Kuparuk River field. A maximum oil production rate is predicted to be 6,000 barrels per day, with total expected recovery approximately 25 million barrels of oil over a field life of 30 years.

GORDON POSPISIL

The Southern Miluveach unit, or SMU, lies between the Kuparuk River and Colville River units on Alaska's North Slope. The Mustang field, originally developed by Brooks Range Petroleum Corp., produced for just one month, a total of 10,999 barrels in October 2019, according to Alaska Oil and Gas Conservation Commission records.

The Mustang Development area is adjacent to the western boundary of the Kuparuk River unit and is approximately 4.5 miles west of existing KRU Drill Site 2M.

Gordon Pospisil, president and CEO of both Finnex and of Mustang Holding, said Finnex will become unit operator and return the unit to production and reconnect the Mustang pipeline. Of four wells drilled at the Mustang Pad, Pospisil said one is producible in paying quantities.

During construction 120 jobs are expected, he said, with 10 to 20 permanent jobs at the field.

Ties into Alpine line

The Mustang Pad was described in the proposed CPlan as a 17-acre gravel production pad, located off of Mustang Road, a 5-mile spur road beginning at the Kuparuk River unit's DS 2M Pad. Associated facilities to support Finnex's project include wellhead facilities, on-pad and off-pad piping/manifolds, process facilities and a trucking terminal.

After the 1,150-foot Mustang pipeline is reconnected, crude oil will be pumped from storage tanks into the Alpine Transportation Co. common-carrier pipeline just southeast of Mustang Pad.

Shared wellbores, use of horizontal drilling technology, and long-reach wells will maximize production while minimizing surface impacts.

Process facilities on Mustang Pad include all facilities and utilities necessary to separate oil, water, and gas, and produce a crude oil product stream that meets the quality specifications of TAPS, the Trans-Alaska Pipeline System.

Mustang Pad process facilities are currently designed to handle peak rates up to 5,000 barrels of oil per day, along with associated gas and water, for a peak fluid (oil + water) capacity design of 7,500 barrels of fluid per day. Produced gas is dehydrated, compressed and used for fuel gas. Excess gas beyond what is necessary to provide fuel gas is re-injected into the Kuparuk River reservoir.

The 38 wells will be enclosed in unheated well shelters. Surface safety valves with associated hydraulic control panels will be located in the well shelter.

Production and gas injection wells will also have subsurface safety valves actuated with a hydraulic control panel that are within 660 feet of the on-site operations camp.

Allocation of producer well volumes will be accomplished using a Schlumberger 3-phase Vx meter to test individual wells in accordance with state regulations. In addition to central process facilities and the drill site facilities associated with the wells, the Mustang Development will also include support infrastructure (non-process) such as an operations camp for staff housing, maintenance and a control room.

During the construction phase, the site plan includes provision for a construction camp and a construction support complex. ●

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● EXPLORATION & PRODUCTION

Hilcorp plans continued drilling at Kenai

Under 2023 POD, one well spud, two more planned by March; depending on results, up to two additional wells planned under 2024 POD

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has filed its plan of development and operations for the Kenai unit with the U.S. Bureau of Land Management for the period April 1, 2024, through March 31, 2025. Kenai is a major natural gas field, one of Cook Inlet's largest, with Alaska Oil and Gas Conservation Commission production data showing the field averaged 18,486 thousand cubic feet of gas per day in January, the most recent month for which information is available.

Production at Kenai is in decline, with this January's volumes down 17.7% from a January 2023 average of 23,079 mcf per day and that vp;I,e down 17.2% from a January 2022 average of 27,856 mcf per day.

In the 2023 plan, covering April 1, 2023, through March 31, 2024, Hilcorp planned three wells, one of which was spud in December, the second planned for a February spud and the third for March, although the company told BLM that spud date could be earlier.

The company told BLM it completed 14 workover and wellwork projects during the 2023 POD, beginning in June and going through January, including returning wells to production which had been shut-in or had coil cleanouts or other work; recompleting wells into different zones; and isolating sands and/or adding perforations.

Facilities work included converting existing and installing new flowlines, electrical and instrumentation to accommodate wells returned to production and new wells. At the grind and inject facility Hilcorp performed two coil tubing cleanouts on injection wells and one perforation add to help maintain injection and isolated, leaned and inspected the T-300 injection storage tank, along with repairs "and internally coated the floor and first shell course and returned the tank to service."

2024 POD

The 2024 POD, covering April 1 through March 31, 2025, includes new wells, depending on results of drilling in the 2023 POD, Hilcorp said, with as many as two wells possible with drilling in the fall of 2024 and the winter of 2024-25.

Several uphole recompletions are planned, along with perforation adds and rig workovers, with the wells to be identified following evaluation. Work may include coil cleanout operations and adding or isolating Sterling or Beluga sand perforations.

Facilities work will include routine operations and repairs and converting existing or installing new flowlines, electrical and instrumentation equipment to accommodate wells returned to production and drilled in 2024-25.

At the grind and inject operation, Hilcorp said it would plan and design phase 1 of storage and processing for contaminated gravel, with phase 1 scope including installing covered storage containment and processing area at pad 41-18 "for utilizing a portable rock crushed to process and transfer gravel to the G&I processing plants." ●

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● EXPLORATION & PRODUCTION

Hilcorp submits small inlet field PODs

Ivan River, Lewis River, Pretty Creek gas fields north of Beluga River on west side, combined January production accounted for 2%

By KRISTEN NELSON
Petroleum News

On March 1 Hilcorp Alaska submitted plans of development to the Alaska Department of Natural Resources' Division of Oil and Gas for three small natural gas fields on the west side of Cook Inlet north of the Beluga River field — Ivan River, Lewis River and Pretty Creek. All three plans cover June 1 through May 31, 2025.

In January, the most recent month for which Alaska Oil and Gas Conservation Commission production data are available, the three fields combined accounted for just over 2% of Cook Inlet gas production, with no production from Pretty Creek in that month.

Ivan River

Ivan River has the most production of the three, averaging 2,720 thousand cubic feet per day in January, 1.3% of inlet production.

In its POD Hilcorp said the field produced 2,246 million cubic feet in calendar year 2023.

During the 2023 POD, Hilcorp executed three through tubing workovers, adding perforations in three wells and also doing a cement squeeze in one of them.

In facilities work, the company optimized piping to compression to match well behavior, beginning with mobile compression and now has permanent compression in place.

In addition, three separator packages were installed for solids knock out, although a planned facility water disposal system upgrade was not done.

For the 2024 POD, Hilcorp plans to continue evaluating "existing completions for rig workover and subsurface opportunities," and continue evaluating opportunities for delineation drilling within the Ivan River Sterling-Beluga and Tyonek participating areas.

There is the possibility of one additional grassroots well at the field, probably spud in the 2025 POD, but there may be pad/facility work needed during the 2024 POD period to support that drilling.

Uphole recompletions, perforation adds and rig workovers are anticipated during the 2024 POD, Hilcorp said, which may include coil cleanout operations and adding or isolating Sterling or Beluga sand perforations.

Facility projects include installation of a coalescer for compression, well tie-in and pad expansion if needed for a 2025 well and routine repairs as needed.

Lewis River

While there was no production from the Lewis River gas pool No. 1 participating area during 2023, production was maintained from gas pool No. 2, with 277 million cubic feet produced in 2023.

Also during the 2023 POD, Hilcorp drilled LRU C-02, which came online in September. Although initial Tyonek perforations were unsuccessful, additional Tyonek and Beluga sands were perforated with initial production of 2 million cubic feet.

The company added line heater and separator to support production from LRU C-02.

For the 2024 POD, Hilcorp plans to continue evaluation of drilling within the Sterling-Beluga and Tyonek participating areas and anticipates wellwork and workover projects which may include coil cleanouts and adding or isolating Sterling or Beluga perforations.

The company also plans to install a coalescer for the Lewis River compressor.

Pretty Creek

There is just one active well at Pretty Creek, Pretty Creek Unit 2, which AOGCC data show produced only in some months of 2023. Hilcorp said production for 2023 was 2 million cubic feet.

The company replaced the reboiler at Pretty Creek during the 2023 POD to support unit operations.

For the 2024 POD, Hilcorp is continuing to evaluate delineation drilling opportunities within the Sterling-Beluga sands, and "will continue to attempt production from the Pretty Creek 02 well."

Up to two development wells are possible targeting Sterling, Beluga and Tyonek sands.

Several uphole recompletions are anticipated, "perforation adds and rig workovers to existing wells to help maintain and increase productivity," with possible projects including coil cleanout operations and adding or isolating Sterling or Beluga sand penetrations.

The company will also evaluate pad or infrastructure projects if there is drilling activity in 2024 or 2025. ●

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THIS MONTH IN HISTORY

PRA final draft of report coming soon

20 years ago this month: Shoppers guide for space in North Slope facilities being compiled on contract with state to study costs

Editor's note: This story was first published in the March 7, 2004, issue of Petroleum News.

By KAY CASHMAN

Petroleum News

The company preparing a "shoppers guide" for space in North Slope production facilities expects to submit a final draft to the Alaska Division of Oil and Gas within the next three weeks.

Petrotechnical Resources of Alaska turned in its first draft Feb. 1, 2004, and expects to complete the "final draft of the study before the end of March," PRA managing partner Tom Walsh told Petroleum News March 3, 2004.

Walsh is the "project lead" for the Anchorage-based oil and gas consulting firm's contract with the state of Alaska to study the cost of purchasing capacity in North Slope oil infrastructure — infrastructure primarily owned by the slope's largest producers, BP Exploration (Alaska), ConocoPhillips Alaska and ExxonMobil.

Waiting on Alpine

PRA's final report will focus on nine North Slope production units, including Prudhoe Bay, Kuparuk River, Point McIntyre, Lisburne, Endicott, Milne Point, Colville River which includes the Alpine field, Northstar and Badami, which is in a warm shutdown. Walsh said the only information they "are waiting on" is from the owners of the Alpine unit, which is not likely to have unused capacity any time in the immediate future.

The state paperwork for the pilot study, awarded to PRA on June 26, 2003, suggests the division will serve as a clearinghouse at a preliminary level to give new players a sense of the landscape on the North Slope.

"The objectives of this project are to reduce entry barriers regarding facility sharing and to improve facility access to exploit potential efficiencies, minimize waste and accelerate oil field development," Walsh said.

Political sensitivities disappeared over time

Initially, there was some political sensitivity around the study, Walsh said. New players and non-facility owners were more enthused about the project than the North Slope facility owners who had to initiate technical work to provide the information PRA was asking for.

But that changed, Walsh said.

"We spent a lot of time initially … creating a cooperative environment … showing how the results would be of mutual benefit to all parties," he said.

Those efforts paid off.

"I was very pleased, and a bit surprised, by the high level of cooperation demonstrated by all of the companies and agencies involved," Walsh said. The information supplied by the facility owners and operators reflected "a very high level of effort and thought devoted to the topic of facility access."

Likewise, he said "the input from third-party producers has been very thoughtful, and many innovative and constructive ideas … emerged in the course of discussions and correspondence over the past nine months."

Over the past three months, PRA's focus has been on "synthesizing the input from all contributors into what we hope will be a useful document for those interested in pursuing facility sharing agreements," Walsh said.

Among other things, PRA's task list included the following:

- Gather, organize and disseminate information regarding existing North Slope production facility capacities, throughput and constraints;
- Identify areas of potential need for excess production capacity, based on industry activity;
- Describe the existing methodologies utilized to calculate facility access fees for satellite field production, and discuss alternative methodologies which balance the needs of owners and third-party producers; and
- Characterize the benefits and shortcomings of facility sharing from the independent producer perspective.

The final result, Walsh said, will help "define the physical and commercial landscape characterizing facility access on the North Slope, recognizing the need to compensate facility owners for their investment and negative production impacts while offering significant operational and commercial advantages to third-party producers."

The PRA team members involved in the facilities study included Walsh, Cathy Foerster, Jan MacDonald, Bob Kaltenbach, Chantal Walsh and Pete Stokes. ●

JUDY PATRICK

From March 7, 2004, issue: Oil companies interested in the cost of buying space in North Slope facilities — such as the Central Gas Facility Prudhoe Bay pictured above — will soon be able to contact the Alaska Division of Oil & Gas for preliminary information.

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TMX NUMBERS

executive officer of MEG Energy, one of TMX's leading shippers.

"It's good news not only for us but everybody in the heavy oil business," he told reporters after a conference call March 1 and a day after the Alberta government released its 2024-25 budget. The budget estimated that every US$1-a-barrel drop in the benchmark price of Western Canada Select would add C$600 million to government revenues.

Alberta looks forward to revenue

Alberta Premier Danielle Smith hailed Evans's comments, noting she was crossing her fingers that TMX would be online by the third quarter, increasing Alberta's export capacity and helping the province gain some clarity on what it could expect "in coming years."

"If we see an increase in our production by 600,000 bpd you can just do the math on that … if it's about $75 a barrel we get about one-third of that in royalties," Smith said.

In a recent regulatory filing with the Canadian Energy Regulator, the government corporation that owns TMX said it expects the final price tag for TMX to be about C$10 billion higher than last spring's C$31 billion cost estimate.

Analyst Phil Skolnick of Eight Capital said the startup of TMX should lower the price differential for WCS and remove the risks of it widening significantly as Canadian oil production continues to set records. "We're getting close, if we're not already there, to basically having supply outpacing pipeline capacity out of Western Canada," he said. "For Canadian oil in general it provides room for growth."

The Alberta budget forecasts that West Texas Intermediate crude prices will average US$74 a barrel in the new fiscal year.

Adam Hardi, a vice president with Moody's Investors Service credit rating agency, called the forecasts "relatively conservative," noting they are below current oil prices of almost US$80 a barrel.

The imminent startup of TMX should be a big benefit to Alberta, said Pedro Antunes, chief economist with the Conference Board of Canada. "If we hadn't seen the green light on TMX coming into service that would have been a significant downside cost," he said.

—GARY PARK

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OIL PRICES

ANS slid 47 cents to close at $81.92, WTI slipped 28 cents to close at $78.26 and Brent edged 6 cents lower to close at $83.62.

On March 6, ANS traded at a 62-cent discount to Brent, while holding a $3.21 premium over WTI.

Oil rose March 6 despite a rise in U.S. inventories reported the same day by the U.S. Energy Information Administration.

U.S. commercial crude inventories for the week ending March 1 — excluding Strategic Petroleum Reserve supplies — increased by 1.4 million barrels from the previous week to 448.5 million barrels, 1% below the five-year average for the time of year, the EIA said.

The gain was a slightly bullish surprise; analysts in a Reuters poll had expected a 2.1 million barrel build.

Gasoline consumption signaled strong demand.

Total motor gasoline inventories decreased for the period, down a robust 4.5 million barrels to 239.7 million barrels, 2% below the five-year average for the time of year, the EIA said.

U.S. Federal Reserve Chair Jerome Powell was noncommittal to a date for a reduction of U.S. benchmark interest rates during March 6 testimony to Congress.

Powell told the House Financial Services Committee that the Fed policy rate is likely at its peak for the current tightening cycle.

"If the economy evolves broadly as expected it will likely be appropriate to begin dialing back policy restraint at some point this year, but the economic outlook is uncertain and ongoing progress toward our 2% objective for inflation is not assured," Powell said.

"Reducing policy restraint too soon or too much could result in a reversal of progress we've seen on inflation and ultimately require even tighter policy to get inflation back to 2%," he said. "At the same time reducing policy restraint too late or too little could unduly weaken economic activity and employment and considering any adjustments to the target range for the for the policy rate we will carefully assess the incoming data evolving outlook and the balance of risks."

The dollar fell against other currencies after Powell's remarks, a bullish factor for crude due to resulting improved affordability for oil buyers using other currencies.

Saudi announcement offsets weak China demand

On March 3, the Saudi Arabia Press Agency reported that Saudi Arabia will extend its voluntary crude production cut of 1 million barrels per day through end of second quarter 2024.

Russia will reduce its production and exports by 471,000 bpd through the end of June, according to Russia Deputy Prime Minister Alexander Novak.

Both announcements were widely expected by crude market players, and as such, they didn't send prices soaring.

China continues to be a drag on oil prices.

China's property market represents 25% of China's GDP and 70% of household wealth, and current weakness in the property market affects consumer demand.

China is experiencing pervasive high youth unemployment.

Export markets are underperforming, and the manufacturing sector is contracting.

China's official manufacturing PMI fell for the fifth consecutive month, from 49.2 in January to 49.1 in February.

China has announced a 5% economic growth target, but analysts were disappointed that the government didn't announce any major stimulus initiatives to boost the economy to that level.

Chinese fortunes may be improving, however.

Chinese customs data released March 7 showed some improvement in the county's foreign trade, bolstering oil prices in Asian trading. The news arrested a slide in early trading, leaving WTI and Brent near their March 6 closing prices, as Petroleum News went to press.

China posted a 5.1% rise in oil imports in the first two months of 2024 from a year earlier to some 10.74 million bpd, the customs data showed, as refiners ramped up crude purchases to meet anticipated fuel sales for the Lunar New Year holiday, Reuters reported, adding that China's January-February refined products exports dropped 30.6% year on year to 8.82 million tons, reducing supplies for global markets.

"China's trade balance data is a positive sign for the oil market's demand outlook," Auckland-based independent analyst Tina Teng told Reuters. ●

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Petroleum news — Oil Patch Bits

PND Engineers, Inc. announces promotion of 4 engineers

PND Engineers, Inc. said Feb. 29 that it recently promoted four engineers in its Anchorage office: Jared Kinney, PE; Cameron Klatt, PE; Kannon Lee, PE; and Taylor Mortensen, PE. All four engineers, three of whom were born and raised in Alaska, recently passed their Principles & Practice of Engineering exams in the state of Alaska and were promoted to PND senior engineers. Klatt previously appeared in the Business Spotlight in February 2024.

Jared Kinney, PE

Kinney, a Chugiak High School and University of Alaska Anchorage alumnus, has over five years of professional civil engineering experience in Alaska. Kinney was hired at PND in November 2023. His primary practice at PND will be hydraulic and hydrologic engineering projects, specializing in site improvements, drainage, and sewer/wastewater utilities.

Kannon Lee, PE

Lee has a bachelor of arts degree in history from Dartmouth College, a bachelor of science degree in civil engineering from the University of Alaska Fairbanks, and a master's degree in geotechnical engineering from the University of Alaska Anchorage, with a focus on stability, seismic engineering, and frozen ground engineering. Lee, who was hired in April 2019, conducted his thesis on "Predicting Thaw Penetration and Permafrost Subsidence due to Warming Air Temperatures on Alaska's North Slope."

Taylor Mortensen, PE

Mortensen, a West Anchorage High School and Montana State University alumnus, is a former flight engineer with the U.S. Navy. Mortensen, who was hired at PND in May 2019, has provided marine structural engineering and bridge design/inspection services throughout Alaska, including several projects on the North Slope. He is a certified Federal Highway Administration Team Leader and IRATA International Level 1 Rope Access Technician.

PND, a dynamic multidisciplinary firm founded in Anchorage in 1979, maintains a staff of professionally licensed engineers and land surveyors who comprise more than half of our workforce, including our newest professionally licensed engineers.

CAMERON KLATT

JARED KINNEY

KANNON LEE

TAYLOR MORTENSEN

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 AGREEMENT

cost of diesel fuel had increased significantly since the original 16-cent pricing had been set. At the same time, there had been a 22% increase in project costs. And at the 22-cent price, the cost of the geothermal energy would still be significantly lower than the cost of diesel fueled power, Matthews had said.

OCCP is seeking a price adjustment that would satisfy investors in the project while also lowering the cost of energy in Unalaska, Matthews commented.

As recently as January OCCP announced that it was approaching a final investment decision for the project. However, although the project has been planned and permitted, the company has been struggling to find the means to fully fund the project.

City manager recommendation

In a memo to the city council, for discussion at the Feb. 27 council meeting, City Manager William Homka recommended allowing the PPA to expire. And during the meeting several council members, while supporting the concept of developing the geothermal energy, expressed concern about continued support for the project, given recurring delays in the project timeline and the requested increase in the price of the electricity.

The city has been supportive of developing Makushin geothermal power, given the city's aging electrical system and its dependence on diesel fueled generation. One council member commented that the city had placed on hold investigations into the use of wind power, given the prospect of obtaining geothermal power. Because of the planned geothermal power system, the city had also decided not to proceed with the acquisition of a flywheel system and battery energy storage, to stabilize renewable energy supplies, Homka wrote.

Three modifications to the PPA

Homka wrote that there had been three modifications to the original PPA, authorized in August 2020. These modifications have ultimately involved moving the original commercial operation deadline from May 31, 2024, to May 31, 2027, and extending the deadline for project financing from June 10, 2021, to Dec. 10, 2023. Then in December 2023 OCCP notified the city that it needed to revise its project schedule and delay project completion to a date in 2028, Homka wrote.

"The city has been patient and supportively waiting for the project to advance," Homka wrote. "But, in waiting, the city has deferred on investing in electric generation and distribution system needs."

Homka wrote that the requested change in the electricity rate in the PPA from 16 cents to 22 cents would increase the cost commitment for a 30-year PPA from $480 million to $660 million. OCCP is also seeking to sell 20% of its power to another entity, to avoid a potential tax problem associated with selling to a single customer, Homka wrote. There is potential to sell power to a fish processing plant on Unalaska Island.

A need for testing

Homka also commented that OCCP has been working with the Department of Energy to try to gain energy loans for the project but has run into issues relating to the need to conduct tests to confirm the amount of energy that the project would be capable of producing. Testing of the resource would require drilling into the geothermal source — current knowledge of the resource comes from an exploration well drilled several decades ago. The testing might cost somewhere around $25 million to conduct and could not be started until there are suitable weather conditions in a few months time, Homka wrote. There were also issues relating to the required construction of a road to the project site, he wrote.

As a consequence of all of these issues, Homka said that, at this point, the city should allow the PPA to expire.

OCCP responds

Makushin program manager David Matthews filed a memo with the city council, in response to Homka's memo. Matthews wrote that "there has been an incredible amount of progress and milestones accomplished, short of a commitment for a full project financing package." Until a few weeks ago OCCP had understood that full project financing was in sight. The company successfully completed phases 1 and 2 of the Department of Energy loan commitment process but has found that the process for due diligence with DOE has not been as straightforward as DOE had previously indicated.

And there are mitigating circumstances that would support not allowing the PPA with the city to lapse, Matthews wrote. Although OCCP does not yet have sufficient financing to complete the project, the company has secured financing that is allowing the project to proceed. The company has a contract with Ormat Technologies for the engineering and construction of the power plant and has selected contractors for the whole project.

"Timelines have changed only due to the difficulty securing long term financing," Matthews wrote.

OCCP has requested an increase to the electricity rate in the PPA, because the current rate is insufficient to cover all financing options. At the same time, the increased rate would still be lower than electricity rates resulting from diesel generation, Matthews wrote.

A six-month time window

Matthews recommended that a modified PPA should be approved. The city could then give OCCP six months to secure a path to adequate financing. If that financing arrangement is not achieved, the project would come to an end. This six-month time window would not significantly delay the city's efforts to implement an alternative plan for improvements to the electrical system, he suggested.

During the Feb. 27 council meeting Matthews suggested that another option would be to maintain the electricity rate at 16 cents and to seek grant funding to fill the funding gap. Again, OCCP would be given six months to secure the funding. If on the other hand grant funding were to be found after the rate had been increased to 22 cents, it would be possible to reduce the rate back down. At this point OCCP has the necessary permits and has done the engineering for the project. And the project remains a great opportunity for the city, Matthews said.

At the end of the meeting a council member proposed a motion to extend the PPA for a further six months. However, since no one seconded the motion, the motion failed, thus allowing the PPA to expire.

—ALAN BAILEY

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APA DRILLING

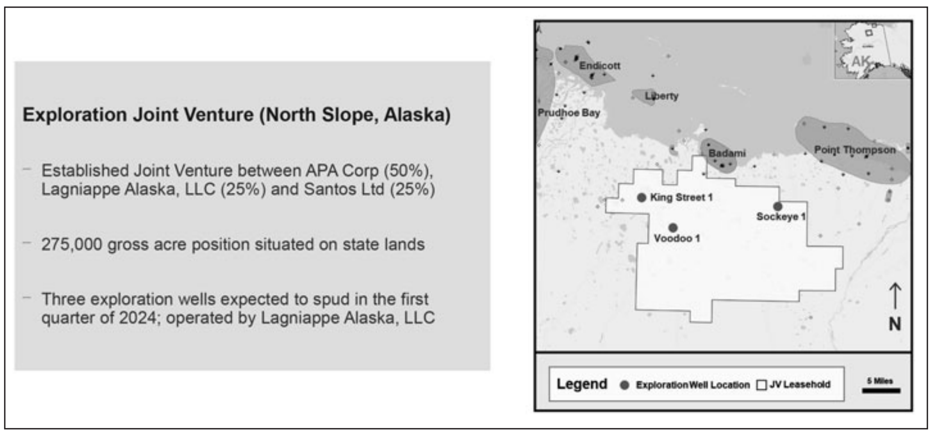
exploration manager, to expand on his response and she said: "What interested us in the block was that we do see materiality with these prospects that warranted exploration."

Armstrong's work led to the discovery of Pikka, a billion barrel new field now under construction west of Prudhoe Bay. He thinks there are new oil discoveries to be made east of Prudhoe Bay in the Brookian.

In a text to Petroleum before the partnership deal was struck between APA, Santos and Lagniappe, Armstrong described the area as "defined off of high effort, reprocessed modern 3D. Really exciting stuff. Big targets."

There has been "virtually no prior drilling in the area. The wells that have been drilled have great shows and some have bypassed pay on old logs," Armstrong added.

When asked in the Q&A segment of the Feb. 22 conference call whether the partners were searching for Pikka lookalikes, Henderson said: "Yes, I would agree with that. We're looking at more play types like Pikka and Willow (both under development now) on the other side of Prudhoe Bay. And that is the Brookian play we're going to be exploring for in a younger sequence but it's absolutely … the same geologic model and set up that we expect to see. Basically just further east than it's been explored for."



APA CORP.

When asked "what's next in the timeline for the program, Christmann said: "We're in the exploration stage right now, so we've done a lot of scoping. It's onshore on state lands. Things can move a little quicker than on federal there. You're close to big pipeline capacity, but let's work through the exploration phase, see what we find and then go from there at a later date. But we're excited about it."

In 2024, APA plans to invest $1.9 billion to $2.0 billion in upstream oil and gas capital worldwide. APA said it will invest for the long term by directing $100 million of the upstream budget toward exploration activities predominantly in Alaska. Approximately $27 million has already been spent in the state on the initial phase of exploration.

"In Alaska it is a position that sits between Prudhoe Bay and ANWR in the Brookian play, so we've entered into the area where we have analogues there that have worked, but they are in an area where that play has not really been explored for. So we're testing … in an underexplored region, As John said we are drilling three wells in this winter season. All of those will spud in Q1," Henderson said.

We've "got good seismic control and they're fully supported so we feel good about them but it IS exploration," Christmann said.

The partners are looking at drilling three more wells next winter, so a total of six wells with three rigs drilling simultaneously. ●

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SOURDOUGH RESET

Jade is the 100% working interest owner of ADL 343112 Segment 2 in Area F. Going back in history, Area F was created as part of Point Thomson settlement talks more than a decade ago. They brought together 7,647 acres of non-contiguous leases in the northeast and southeast corners of the unit. Jade's Sourdough project targets the southeastern leases, known as Tract 32.

"On behalf of Jade and as an eligible person affected by your decision, I hereby request reconsideration of the Point Thomson Area F 2024 6th POD," Opstad wrote in his request for reconsideration.

The basis for reconsideration is "an apparent" DNR and its Division of Oil and Gas' "misperception relative to work accomplished by Jade Energy during the 5th annual POD," which ran from Jan. 1 through Dec. 31, 2023.

"Jade feels that this communication breakdown may have been exacerbated by changes in DNR/DOG project managers over the past several years," Opstad wrote.

DNR and the division were clearly supportive of Jade's efforts to drill an exploration/appraisal well into BP's mid-1990's Sourdough discovery until the division inserted default conditions on Dec. 21, 2022, in Jade's fifth plan of development — conditions the small company had to agree to before DNR would approve Jade's 5th POD.

The conditions

The conditions were as follows, with neither identifying ways to cure a default should circumstances justify a delay of either:

— On or before July 1, 2023, Jade will provide evidence to the division that Jade has funding for the well it plans to drill in Q1/Q2 of 2024.

— On or before Sept. 1, 2023, Jade will provide to the division a rig contract for the well planned to be drilled in 2024.

The default conditions were seen by the investor community as the actions of a hostile agency.

For example. an attorney for a large Alaska Native corporation tasked with looking at the Sourdough project called the division's terms of 5th POD approval "conditions of extortion."

Private investors soured on Alaska projects because of President Joe Biden's stance against the oil and gas industry.

But investors renewed their interest in Sourdough and other projects on state acreage in Alaska during fourth quarter 2022.

"We are actively engaged in money raising for this oil development project," Opstad said in December 2022. "It's gratifying to see interest in oil drilling returning to Alaska."

In an update during an early April 2023 interview with Petroleum News, Opstad said his company had two funding commitments with a third pending

> *"We believe, if we all can get together and 'reset,' then we can continue to provide this Alaskan expertise to move this project forward with the goal of delivering oil to Skid 50 meter as soon as Q2 2025."*

Brookian reservoirs

Potential Brookian reservoirs have been encountered by numerous wells drilled in and near the Point Thomson unit since the 1970s.

Jade's acreage holds two of BP's mid-1990s oil discovery wells, Sourdough 2 and 3. The company drilled the 12,562-foot Sourdough No. 2 well in March 1994 and the 12,475-foot Sourdough No. 3 well in March 1996.

In 1997 BP estimated the prospect held 100 million barrels of recoverable oil.

But BP never pursued development because at the time there was no pipeline near the Sourdough prospect which borders the coastal plain of ANWR on the east. One hundred million barrels of oil did not justify the cost of a pipeline and related facilities. The Point Thomson project had yet to be developed.

During its exploration work from the mid-1990s, BP produced some 2,700 barrels per day by stimulating the vertical Sourdough No. 3 well. Opstad believes that a 5,000-foot horizontal completion into the reservoir would result in significantly higher production.

Jade prepared to use a rig to drill the Jade No. 1 exploration/appraisal well in early 2020. The approximately 12,750-foot well would penetrate "all of the prospective Brookian sand targets that lay between 11,000 feet and the Hue Shale at 12,500 feet," the company said at the time.

But the realities of getting equipment to the eastern North Slope forced Jade to delay the project into early 2021 and then delay the project again into early 2022. The Covid-19 pandemic played a huge part in this, as most North Slope services and supplies were unavailable.

Although Jade signed a memorandum of understanding for use of a drilling rig that required refurbishment, Jade decided that given the over-pressured conditions exhibited by Brookian reservoirs in the Point Thomson area, the rig systems needed to be upgraded to 10,000 psi from the more typical 5,000 psi rating required for rig operations in other North Slope fields — a much more expensive and time-consuming endeavor. Readying the rig for North Slope drilling and a shortage of equipment and supplies on the North Slope because of stepped up activity on major projects prompted Jade to ask for an extension of one year in its 6th POD.

Instead DNR only gave Jade until early March 2024 and put Jade's acreage in default.

Misperception re. work done

So what did Jade accomplish in its fifth POD?

• Well planning — Working closely with SLB (formally Schlumberger) Jade nearly completed well planning for the Jade-1 pilot hole and that effort is expected to be finalized by year end. The Jade team is also well down the road on planning on the J-1H production well.

• Funding — At a mid-year apex, Jade had commitments for approximately $20 million for drilling the first Sourdough reservoir well, which represented roughly 45% of the well drilling and completion budget. That commitment is currently materially less, but Jade continues with its capital raise despite investors being anxious about committing millions of dollars to a project that appeared to lack support from the agency responsible for promoting and regulating oil and gas development in Alaska.

•Work such as the shallow hazard study, anti-collision modeling, drilling fluids program, well casing design and so forth have been completed.

• Third Party Economic Model — As part of its overall evaluation of the Sourdough Development Program, Jade commissioned a third-party economic evaluation of the prospect. Using State parameters and computational methodologies, this work was important because, for the first time, Jade was able demonstrate that the Sourdough development could be commercially viable.

• Permitting — Although not called out as a specific objective for the fifth POD, Jade completed nearly all permitting required to deliver the drilling program. The few permits not in hand are waiting on the resolution of administrative issues.

Request a reset

"We respectfully request a meeting with you," Opstad wrote in his request for reconsideration.

"The Jade principals and management team involved in this project are the same team from Alaska that invested in, managed and re-started the Badami Unit in 2012 and managed, invested in and successfully drilled 10 wells since then; several of these wells were up to 112 miles off North Slope gravel infrastructure," Opstad wrote.

"We believe, if we all can get together and 'reset,' then we can continue to provide this Alaskan expertise to move this project forward with the goal of delivering oil to Skid 50 meter as soon as Q2 2025 and an overall objective of this project coming fully online and producing 35,000 barrels of oil per day by 2028, making it the next project in the 'queue' for supporting construction and operation jobs in the O&G industry. Can we confirm that Alaska is truly 'open for business' or is this phrase just an empty public relations slogan?" Opstad concluded.

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WHAT ABOUT COAL?

power generation in Southcentral (“Cook Inlet region low carbon power generation with carbon capture, transport, and storage feasibility study”).

At issue is depletion of Cook Inlet natural gas sources and while gas is used for more than generating electricity, the low-carbon power generation study noted that Chugach Electric Association, the dominant electricity producer in Southcentral, produces 80% of its electricity burning natural gas.

Alaska has the coal

The low-carbon power study said that combining biomass-coal power generation with carbon capture and storage “presents a compelling alternative” for production of power in Southcentral, with plants proposed to be co-located at the Flatlands Energy Corp. coal lease in the West Susitna region, where existing coal reserves have low ash, metal and mercury content and ultralow sulfur content.

Plant design concepts and costs are based on the 405-megawatt Dry Fork, Wyoming, coal power plant, the 17-megawatt coal power plant recently constructed at UAF and on recently designed carbon capture plants elsewhere in North America.

The CO2 would be moved by pipe and injected at the Beluga River gas field, which, the study says, is forecast to be depleted within 10 years and where the geology is well understood, with Beluga estimated to be capable of holding 60 years of CO2 from a 400-megawatt electric biomass-coal power plant. The study said Beluga operator Hilcorp Alaska has said injection could begin while the field is still in production.

Lower carbon

Current carbon capture allows 90% or more of carbon emissions from power plants to be removed, “resulting in lower CO2 emissions than existing or new natural gas power plants without CCS.”

The study also found that biomass-coal energy supply with CCS is lower cost than natural gas generated energy, with or without CCS, “and biomass-coal energy supply with CCS provides lower CO2 emissions than the current natural gas energy supply without CCS.”

Federal 45Q tax credits accrue to the owner of the CCS facility, so as long as both the CCS facility and the powerplant have the same owner, “CCS lowers the cost of electricity for biomass-coal generation because 45Q tax credit revenues exceed CCS cost, while CCS for natural gas increases electricity cost due to Southcentral’s high gas prices,” the study found.

Facilities requirements

In addition to the mine and the plants, requirements include access to the mine — there is an existing West Susitna winter road, with an all-season West Susitna Access Road in the permitting phase, the study said.

There is a permitted pipeline corridor on the north shore of Cook Inlet which might be amended for electrical transmission and CO2 transport, and a regional 500-plus megawatt capacity power grid intertie at the Beluga power plant, or an alternate tie-in near Port MacKenzie. Port MacKenzie is also available for large machinery and equipment delivery and a relevant workforce exists in the state.

Pipeline transport of the CO2 to Beluga would be expensive, the study said, so appraisal of injection opportunities at the mine site would potentially identify savings if an appropriate reservoir could be located.

Technology, coal

The proposal in the study, a biomass-coal fired power plant using circulating fluidized-bed technology, is similar to the recently completed power plant at UAF, the study said.

CO2 capture could be as high as 95% or more at the proposed plant, depending on design, operating conditions and other factors.

The coal at the Flatlands Energy lease has properties comparable to that mined at Usibelli in central Alaska, although the study said coal energy quality is higher in the Flatlands Energy coal, while it is similar to Usibelli in having ultralow sulfur and low mercury and metals, with its low contaminant content making it similar to the coal used in the new low emissions combined heat and power generation station at UAF.

The Flatlands Energy mine is estimated to have 150 years or more of reserves, based on “low to reasonable extraction ratios” with competitive extraction costs because it is a shallow mine.

Bettle-killed spruce could provide a source of biomass, the study said, along with other forest management biomass, agriculture and/or municipal solid waste.

There are potential industrial customers, with the Flatlands Energy reserve some 25 miles from a Nova Minerals advanced gold-rare earth elements exploration project and from a US GoldMining gold-copper project which is in an earlier stage of exploration and some 200 miles from the proposed Donlin Gold mine, a project in the final investment decision stage.

Existing Southcentral capacity

The study said Railbelt utilities have some 1,600 megawatts of fossil fueled capacity, but only about 800 megawatts of that is efficient, some 600 megawatts of modern natural gas-fueled plants and some 200 megawatts of coal- and oil-fired plants, along with some 200 megawatts of renewable capacity, primarily Bradley Lake hydropower.

When the National Renewable Energy Lab did a recent analysis of Railbelt energy it found that 75% of fossil-fuel based generation would have to be retained to meet demand even with extensive new renewable sources including wind and solar. ●

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