World, Alaska topsy turvy on oil, gas; ANWR gas line to Kaktovik?

In a switch that illustrates the world’s oil trade is out of whack, an oil tanker sailed in December from Houston to the United Arab Emirates, a Persian Gulf petroleum province where 2-3 million barrels a day of crude is exported to feed a giant sovereign wealth fund.

Per U.S. government sources researched by Bloomberg and published in a Feb. 6 article, the tanker was carrying very light Texas crude from tight oil wells (commonly and often incorrectly referred to as shale oil).

The cargo of American condensate is preferred to regional grades because its superior quality is better-suited for U.A.E.

**Conoco sells last Cook Inlet asset, Nikiski LNG facility, to Andeavor**

ConocoPhillips has sold its liquefied natural gas facility at Nikiski on the Kenai Peninsula to Andeavor, formerly called Tesoro, the operator of the nearby Nikiski oil refinery.

“The sale closed and the operatorship was transferred to Andeavor on Jan. 31,” ConocoPhillips spokeswoman Amy Burnett told Petroleum News in a Feb. 2 email.

“We can confirm that Andeavor has acquired the Kenai Liquefied Natural Gas (LNG) facility,” Andeavor spokesman Scott LaBelle told Petroleum News. “This acquisition further strengthens our integrated value chain by optimizing our operations in Kenai and providing low-cost fuel for our refinery to produce the fuels that consumers in Alaska need to keep their lives moving.”

The LNG facility is the last of ConocoPhillips’ Cook Inlet

**Anadarko: 25 Alaska years**

Company leaving the state, sells remaining North Slope assets to ConocoPhillips

Anadarko also partnered with ARCO Alaska Inc. (subsequently ConocoPhillips Alaska Inc.) in an exploration venture that led to the discovery of the Alpine oil field in 1994 in the western North Slope.

1997. Development was not pursued at that time, but in 2007 the Theta lease became part of an expanded Oooguruk oil field, operated then by Pioneer Natural Resources Alaska.

**BP says its global business is growing; mentions success, opportunities in Alaska**

During BP’s earnings call for its fourth quarter 2017 results, company executives presented an upbeat message. The company is on track for bringing 800,000 barrels of new major production on line by 2020, said Bob Dudley, BP group chief executive. In 2017 the company’s exploration programs discovered around a billion barrels of new resource; reserves replacement ran to about 143 percent, and the company sanctioned new projects in Trinidad, India and the Gulf of Mexico. Bernard Looney, BP chief executive upstream, praised the company’s Alaska team for maintaining oil production from the Prudhoe Bay field flat at a level of around 280,000 barrels per day for three years. The team’s ability to manage the gas and the field optimization provides a great example of what can be achieved, he said.

Looney also commented that the new tax rules under the Trump administration may...
Walker’s tax credit bonding bill introduced

By KRISTEN NELSON
Petroleum News

The Walker administration has introduced a bill to allow the state to issue bonds to pay for its cashable oil tax exploration credits.

In a press release on the bill the governor said he was “proposing this bill to achieve fair resolution to the small independent oil exploration company tax credit purchase program, and to free up capital for the small companies who participated in the program to resume investing in future oil exploration leading to additional production. Passage of this bill would allow the state to move past the uncertainty on these tax credits and focus on growing Alaska.”

The bill allows for payment of credits at a discounted rate so there would be no additional cost to the state. There is a remaining balance of $800 million in cashable oil and gas exploration tax credits, and an additional amount up to $200 million is expected to accrue in the next two to three years before the last credit programs ended, the administration said.

State corporation

In a letter accompanying the bill, Walker said the bill would create a state corporation authorized to issue bonds to purchase oil and gas exploration tax credits. The state’s program to purchase oil and gas tax credits was ended with the passage of House Bill 111 last year. The governor said major producers have always been ineligible to participate in this program, which provided small producers and explorers to earn credits.

Alaska has purchased more than $3.5 billion in these credits since the program began in 2007, the governor said, but with the downturn in oil prices and the state’s budget challenges it is no longer able to purchase the credits.
EIA sees $60 range for Brent in ’18, ’19

US crude estimated at 10.1 million bpd in January, for a new monthly record; 10.6 million expected in 2018, 11.2 million in 2019

continued from page 2

BONDING BILL

By KRISTEN NELSON
Petroleum News

North Sea Brent crude oil spot prices averaged $69 per barrel in January, the U.S. Energy Information Administration said in its monthly Short-Term Energy Outlook, released Feb. 6. That $69 average is up $5 from the December level. Average Brent prices have increased for seven consecutive months, moving above $70 on Jan. 11 for the first time since December 2014.

EIA Administrator Dr. Linda Capuano said in a Feb. 6 statement that, “EIA’s forecast expects Brent crude oil prices to be in the $62 per barrel range in 2018 and 2019. That’s down a bit from current levels, as strong U.S. pro-
duction growth is expected to help moderate global prices.”

EIA said it expects West Texas Intermediate crude oil prices to average $4 per barrel lower than Brent in both 2018 and 2019.

U.S. crude oil production is estimated to have averaged more than 10 million barrels per day in January, up 100,000 bpd from December.

“Averaging 100,000 barrels per day last November, a first since 1970, EIA estimates U.S. crude oil climbed to 10.1 million barrels per day in January, which would be the highest for any month on record,” Capuano said.

“February’s short-term outlook revises the forecast for increased oil production over the next two years,” she said. “We now expect U.S. crude oil production to average 10.6 million barrels per day in 2018 and 11.2 million barrels per day in 2019.”

EIA said an average of 10.6 million bpd this year would mark the highest average annual U.S. crude oil production level, surpassing the 9.6 million bpd average in 1970.

Natural gas

U.S. dry natural gas production averaged 73.6 billion cubic feet per day in 2017 and EIA is forecasting that it will reach 80.3 bcf per day this year.

“Natural gas is poised to set a record annual increase and record production level in 2018,” Capuano said. “EIA expects a production increase of 6.7 billion cubic feet per day in 2018, climbing from 73.6 billion cubic feet per day in 2017 to more than 80 billion cubic feet per day,” with growth from 2018 to 2019 projected to be lower, but close to 3 percent year-over-year, she said.

Linda Capuano

Henry Hub natural gas spot prices averaged $3.88 per million British thermal units in January, up $1.06 from December, EIA said, with cold temperatures east of the Rocky Mountains early in January contributing to high levels of natural gas consumption. There was also a reduction in production because of well freeze-offs, the agency said, with the combination resulting in record high natural gas inventory withdrawals in mid-January, which contributed to rising prices.

“Record natural gas production in the coming months should allow prices to pull back from January’s highs,” Capuano said, with increases in production in February expected to continue through 2019, reducing natural spot prices to an average of some $3.20 per million Btu in 2018 and $3.08 in 2019.

EIA expects Henry Hub to average $3.34 per million Btu in February.

Crude oil

EIA said oil inventories in the U.S. and globally have fallen steadily over the past seven months, one contributor to Brent reaching more than $70 per barrel in mid-January. The agency said there may also have been some price support from the Organization of the Petroleum Exporting Countries, where some members at a monitoring committee meeting suggested extending the current production reduc-
tion agreement beyond the end of the year.

“Rapid declines in Venezuelan crude oil output are also likely contributing to higher crude oil prices,” EIA said.

U.S. imports of Venezuela crude declined to some 400,000 bpd for the four weeks ending Jan. 26, the agency said, approaching the lowest level in decades, with trade press reports indicating that workers at the Venezuela natural oil company may be fleeing the company amid social unrest.

“Improved global economic growth expectations could also be supporting oil prices,” EIA said.

The decline in crude oil inventories in the U.S. was 6 mil-

lion barrels in the first four weeks of the year, contrasting to a five-year average build of 14 million barrels in that same period.

And U.S. crude oil exports were up, averaging 1.4 mil-

lion bpd for the four weeks ending Jan. 26, compared to an average of 700,000 bpd in January 2017.

Oil prices

EIA said U.S. crude oil prices compared to Brent diverged from recent trends in January, with the Light Louisiana Sweet price difference with Brent falling from a slight premium to Brent to $1 or more under Brent for 23 consecutive trading days in December and January, the longest stretch where LLS traded more than $1 under Brent since February and March 2015.

LLS remained lower even after the Forties Pipeline was restored to full service, and EIA said the discount could be

see EIA OUTLOOK page 4

contacts

LINDA CAPUANO

By KRISTEN NELSON
Petroleum News

oil and gas tax credits at a discount—would apply automatically to certain cor-

mangements. He said this payment delay “as

a five-year average build of 14 million barrels in that same period.

The Department of Revenue would

would apply automatically to certain cor-

porate income tax credits for gas storage

facilities and in-state oil refineries, with

the lower discount based on the state’s true interest cost plus 1.5 percent, current-

ly estimated at about 5.5 percent.

However, the governor said, the corpo-

ration would not issue bonds unless the discount rate applied in the department’s purchase of the credits would exceed the state’s true interest cost on the bonds by at least 1.5 percent per year.

The Department of Natural Resources would handle agreements for overriding royalty interests and waivers of confiden-
tiality for early release of seismic data.

The governor said the bill would have an immediate effective date, allowing the Alaska Tax Certificate Bond Corp., the departments and those request-

ing purchase of the credits “the ability to start work right away to address these tax

credits as quickly as they are submitted.

Since 2016, Walker said, the state has appropriat-
ded funds based on a statutory formula, resulting in the large accrued balances. He said this payment delay “as

resulted in significant uncertainty for Alaska’s small producers, some of whom have had a difficult time borrowing addi-
tional money to complete their projects.”

Commissioners as directors

The Alaska Tax Certificate Bond Corp., to be created by the legisla-
ture, would be authorized to issue up to $1 billion in bonds to finance purchases of oil and gas tax credits at a discount from face value, the governor said. The discount offered to holders of the credits would be used to pay the cost of financing the bonds, Walker said. He also said the bonds would not constitute a general obliga-
tion of the state; authority to issue bonds would expire Dec. 31, 2021.

The Department of Revenue would have authority to negotiate purchase of tax credits at less than full value when bond proceeds are used for those purchas-
es, and applicants would have to notify the department of Feb. 6. To purchase tax credits from bond proceeds at a discount ed amount.

The face amount of the tax credits would be discounted each year by 10 per-
cents, the governor said, although a lower discount could apply for applicants agreeing to conditions which benefit the state, including: overriding royalty interests,
Northstar-Kuparuk oil pool rules approved

By KRISTEN NELSON
Petroleum News

The Alaska Oil and Gas Conservation Commission has approved pool rules for the Northstar-Kuparuk oil pool at the North Slope Northstar unit, which straddles state and federal leases in the Beaufort Sea. Hilcorp Alaska, which took over Northstar as part of North Slope acquisitions from BP at the end of 2014, applied in October 2016 for an order defining a new pool within the Northstar unit and for rules governing pool development and operation.

BP, the former Northstar operator, began producing from the Ivishak formation at Northstar in 2001 and in 2006 began testing the Kuparuk reservoir within Northstar. The majority of the Northstar Kuparuk reservoirs are assigned to less compartmentalized C sands where wells will drain larger areas. Hilcorp is continuing to gather data on the C sands and is evaluating the potential of implementing a gas reinjection project to improve ultimate recovery from the C sand.

The commission approved pool rules, including commingling of production from the C and A sands due to the small size of the A sand and proximity to the C sand.

Hilcorp will continue to collect reservoir performance data to determine whether an enhanced oil recovery project will work for the C sand, and the commission is granting a temporary waiver, through Dec. 31, 2019, to the gas-oil ratio in its regulations for the collection of additional reservoir performance information.

In 2012 BP applied for designation of the Kuparuk producing area at Northstar as the Hooligan participating area. That original PA included only the Kuparuk C sands. In 2016 another Northstar well began gas and condensate production from the deeper Kuparuk A sands and Hilcorp applied for an expansion of the PA, which was granted in early 2017.

Northstar

Northstar lies offshore the North Slope some 12 miles northwest of Prudhoe Bay and is developed from the Northstar artificial island drill site. Hilcorp is 100 percent working interest owner and operator at Northstar.

Shell Oil Co. drilled the Northstar discovery well in 1983, encountering oil indicators in the Kuparuk formation. A number of confirmation wells were drilled through 1986, the commission said, with some 30 wells to date having been logged across the Kuparuk reservoir within Northstar. The geologic structure and reservoir have been determined using 3-D seismic survey and well log data.

The Northstar-Kuparuk oil pool is the accumulation common to and correlating with the interval between measured depths of 12,156 and 12,446 feet in the Northstar NS-15 development well, the commission said.

Gas, condensate

The Kuparuk A sands contain a gas-condensate cap with an oil rim; the overlying Kuparuk C sands contain only gas condensate.

The commission said Hilcorp considers the Kuparuk C and A sands to be a gas-condensate reservoir, but said they are considered oil reservoirs because the producing gas-oil ratio is less than 100,000 standard cubic feet per stock tank barrel. The API gravity of oil recovered from the Northstar Kuparuk pool is 38 degrees to 53 degrees, with an average of 47.6 degrees API.

Three wells are currently producing from the Northstar Kuparuk pool. Estimated volumes are 500 to 550 billion cubic feet of gas and 22 million to 25 million stock tank barrels of original oil, with primary recovery estimated at 40 percent and primary recovery plus waterflood at 46 percent. The commission said no new wells are planned and the project is expected to continue until about 2030.

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EIA OUTLOOK

due to the startup of the Diamond pipeline from Cushing, Oklahoma, to Memphis, Tennessee, “which may be lowering the demand for U.S. Gulf Coast crude oil from refineries in the U.S. Midwest.”

WTI Cushing and WTI Midland increased relative to Brent, with the spreads settling at $4.02 and $3.82 per barrel on Feb. 1, increases of $2.30 and $1.70 respectively, since Jan. 2.

“The Diamond pipeline startup and a likely reduction in Canadian crude oil deliveries to Cushing have contributed to a stock draw at the hub of 12 million barrels since the last week of December and likely increased WTI Cushing prices,” while cold weather in Texas led to some production shut-ins, minus the WTI Midland-Brent oil spread.
Brooks Range’s successful flow test of its North Tarn No. 1A well from the Mustang pad in the Southern Miluveach unit produced an impressive 1,292 barrels a day, with proven and probable recoverable oil reserves of 33 million barrels. Company CEO Bart Armfield was delighted with the test results, noting they were “very encouraging … and confirm we are on the right track with our development plans.” Consequently, development of the oil field has been accelerated, with the next phase involving the installation of processing facilities and drilling of up to 18 horizontal production and development wells, leading to first oil in first quarter 2019.

Great test results in accelerated development; first oil early 2019
The Alaska House Resources Committee has introduced a bill, House Bill 322, to increase the financial penalties for spills of oil and other contaminants in the state. The bill would also introduce a new mandate requiring that operators of tanker trucks carrying crude oil must maintain oil spill contingency plans for the trucking operations. The bill also says that produced water spilled along with oil must be included when calculating the scale of a spill. And the bill authorizes the Alaska Department of Environmental Conservation to impose punitive administrative penalties for serious or repeated discharges.

If enacted, the bill would go into effect on Jan. 1, 2019, a date that would allow time for DEC to write appropriate regulations and for oil truckers to develop contingency plans. A prime motivation behind the bill is the fact that the oil spill penalties have not been increased since they were originally set many years ago. Some penalties date back to the 1970s while others date back to the 1990s. DEC recommended many of the provisions in the bill to the House Resources Committee.

**Increased penalties**

DEC has proposed penalty levels that the agency sees as appropriate to the violations involved. In some cases the new penalties reflect or exceed inflation levels since the original penalties were enacted, while in others the new rates come well below inflation adjusted amounts.

In general, the civil penalties for an initial discharge violation would double, relative to their current levels, while penalties for continuing violations would increase by higher factors. For example, the civil penalty for a discharge of less than 18,000 gallons of oil and crude oil would increase from a range of $500 to $100,000 to a range of $1,000 to $200,000. The penalty for each day of a continuing violation would increase from $5,000 to $25,000.

For crude oil spills more than 18,000 gallons, the penalties would increase from $8 to $16 per gallon spilled for a spill of less than 420,000 gallons, and from $12.50 to $25.00 per gallon for a spill of more than 420,000 gallons.

**Agency and court discretion**

For these civil penalties, DEC can choose whether to sue the party responsible for the spill through the courts, with the court able to impose a fine within the prescribed penalty range for the type of spill. During a Feb. 2 meeting of House Resources, Kristin Ryan, director of DEC’s Division of Spill Prevention and Response, explained that DEC has discretion over whether to sue and what level of penalty to assess, depending on the circumstances of the spill and the actions taken by the party responsible for the spill. Similarly, the court can assess what level of fine to impose, depending on the circumstances.

The proposed new statute enabling DEC to impose administrative penalties would allow the department to assess a penalty of not less than $1,000, and not more than $10,000 or $24 per gallon spilled, for egregious discharges of crude oil, petroleum and any substance refined from oil. Being administrative penalties, these penalties would be imposed by DEC and not through a court. And any associated civil penalty would be reduced by the amount of the administrative penalty.

**Concerns about trucking**

Ryan explained that the proposed requirement that the truck transportation of oil will require a DEC approved oil spill contingency plan reflects DEC’s concern that there are now two companies transporting crude oil by highway on the Kenai Peninsula. The contingency plan mandate, as well as requiring the filing of plans, would invoke the need for oil spill drills to test the plans. One of the companies involved in trucking crude is BlueCrest Energy, which transports oil from its Cosmopolitan field in the south-central Kenai Peninsula to the oil refinery at Nikiski in the northern peninsula — Ryan emphasized that the proposed statute is not a criticism of BlueCrest, which she characterized as “doing a great job” in managing its crude oil trucking operations.

Ryan also explained that the proposed inclusion of produced water, salt water that is produced along with oil from an oil field, in the calculations for assessing oil spill volumes reflects the increasing volumes of produced water emanating from the North Slope fields, and the fact that the water is as toxic to the environment as the oil, while typically being more difficult to clean up. In particular, salt from the water tends to persist in the tundra, she said.

**Invited testimony**

During invited testimony to House Resources on Feb. 5 Patti Saunders from...
January ANS crude down 1% from December

Fields reported under Kuparuk hold flat, all other Tax Division North Slope groupings down; December Cook Inlet down from November

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 542,410 barrels per day in January, down 1 percent, 5,277 bpd, from a December average of 547,687 bpd.

Fields reported under the Kuparuk umbrella held steady, up less than 1 percent from December, averaging 147,219 bpd in January, an increase of just 140 bpd from 147,079 bpd. Kuparuk volumes include satellite production from Melwater, Tabasco, Tar and West Sak, all operated by ConocoPhillips Alaska, as well as volumes from the Eni-operated Nikaitchuq field and the Caelus Alaska-operated Oooguruk field.

January information comes from the Alaska Department of Revenue’s Tax Division which consolidates North Slope oil production by major facilities rather than reporting individual fields, providing daily production and monthly averages. More detailed data, by individual fields and pools for Cook Inlet and the North Slope, comes from the Alaska Oil and Gas Conservation Commission on a month-delay basis.

AOGCC data for December show Nikaitchuq averaged 19,348 bpd, up 1.7 percent, 331 bpd, from a November average of 19,018 bpd. Oooguruk averaged 13,651 bpd in December, up 4.8 percent, 331 bpd, from a November average of 13,017 bpd.

Prudhoe umbrella volumes down

Volumes shown by the Tax Division for the BP Exploration (Alaska)-operated Prudhoe Bay field include satellite production from Aurora, Borealis, Midnight Sun, Orion, Polaris, Schrader Bluff and Sag River, as well as volumes from fields operated by Hilcorp Alaska — Endicott (including Eider, Minke and Sag Delta),

AOGCC data show Cook Inlet production averaged 15,769 bpd in December, down 2.7 percent, 429 bpd, from a December average of 485,930 bpd.

Milne Point and Northstar, the ExxonMobil-operated Point Thomson field and Badami, operated by Glacier Oil and Gas subsidiary Savant Alaska. The combined Prudhoe volumes (from the Tax Division) for January total 305,743 bpd, down 0.7 percent, 2,035 bpd, from a December average of 307,778 bpd.

The Tax Division reports Lisburne — part of Greater Prudhoe Bay — separately, including Niaukuk and Point Mclntyre, with production averaging 23,117 bpd in January, down 7.2 percent, 1,785 bpd from a December average of 24,902 bpd.

AOGCC data show the Prudhoe Bay field by itself averaged 239,188 bpd in December, down 1.1 percent, 2,645 bpd, from a November average of 241,833 bpd. Those numbers include Lisburne, Niaukuk and Point Mclntyre, which collectively in December accounted for almost 30,000 bpd.

Badami averaged 375 bpd in December, based on AOGCC data, down 5.5 percent, 43 bpd, from a November average of 478 bpd.

AOGCC data for Endicott show that field averaged 6,719 bpd in December, down 3.4 percent, 236 bpd, from a November average of 6,955 bpd.

Milne Point averaged 19,654 bpd in December, up 9.8 percent, 1,748 bpd, from a November average of 17,907 bpd, while Northstar averaged 8,681 bpd in December, up 4.5 percent, 375 bpd, from a November average of 8,306 bpd.

AOGCC data for Point Thomson show that field averaged 5,524 bpd in December, down 4.4 percent, 244 bpd, from a November average of 5,768 bpd.

From a November average of 9,575 bpd. The big difference between the months is days of operation. Point Thomson has one producing well. In November that well produced for 30 days (total oil for the month was 287,261 barrels); in December, however, that one well was only producing for 18 days (a total of 165,047 barrels for the month). Production was 9,169 bpd for those 18 days but dropped to 5,324 bpd when averaged over the entire month, which is how barrels are reported.

Cook Inlet

AOGCC data show Cook Inlet production averaged 15,769 bpd in December, down 2.7 percent, 429 bpd, from a November average of 485,930 bpd.

Of nine oil fields in the inlet, six had month-over-month production declines. Hilcorp Alaska’s Beaver Creek averaged 67 bpd in December, down 46 percent, 56 bpd, from a November average of 123 bpd.

Granite Point, also operated by Hilcorp, averaged 1,396 bpd in December, up 0.2 percent, 8 bpd, from a November average of 1,388 bpd.

BlueCrest’s Hansen field, the Cosmopolitan project, averaged 32 bpd, down 88 percent, 237 bpd, from a November average of 269 bpd.

Hilcorp’s McArthur River field, Cook Inlet’s largest, averaged 5,315 bpd in December, down 1.2 percent, 65 bpd, from a November average of 5,380 bpd.

Middle Ground Shoal, also operated by Hilcorp, averaged 1,574 bpd in December, up 0.4 percent, 7 bpd, from a November average of 1,567 bpd.

Glacier Oil and Gas’ Redoubt Shoal field averaged 1,011 bpd in December, up 22.2 percent, 184 bpd, from a November average of 827 bpd.

Hilcorp’s Swanson River field averaged 1,683 bpd in December, down 3 percent, 52 bpd, from a November average of 1,735 bpd.

Trading Bay, also operated by Hilcorp, averaged 1,864 bpd in December, down 3.3 percent, 64 bpd, from a November average of 1,929 bpd.

Glacier’s West McArthur River field averaged 1,027 bpd, down 12.8 percent, 150 bpd, from a November average of 1,178 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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PETROLEUM NEWS "WEEK OF FEBRUARY 11, 2018"
Preliminary finding for North Slope sales

Every 10 years the state does a best interest finding for its areawide oil and gas lease sales and it has just issued a preliminary BIF for the North Slope.

In a Jan. 31 preliminary BIF, the director of the Alaska Department of Natural Resources Division of Oil and Gas has found that the disposal of oil and gas resources in the North Slope areawide sale area is in the best interest of the state. The North Slope areawide sale includes all available state-owned lands between the National Petroleum Reserve-Alaska on the west and the Canning River on the east, and from the Beaufort Sea in the north to the Umati meridian baseline in the south, some 5.1 million gross acres.

The preliminary finding is available on the division’s website at https://dog.dnr.alaska.gov/Home/Newsroom.

The division said the preliminary BIF is subject to revision based on public comments received by the division, which are due in writing by April 2. Following review of those comments, the director will make a final determination.

Some nine months prior to each lease sale the division issues a call for new information requesting substantial new information that has become available since the most recent finding, providing a public participation period of not less than 30 days.

Rokeberg retires, Lisankie takes seat

The Regulatory Commission of Alaska said Feb. 1 that Commissioner Norman Rokeberg has retired and former Commissioner Paul F. Lisankie has returned to the commission to fill the remainder of Rokeberg’s term, which expires March 1, 2019.

RCA said Rokeberg announced his retirement Dec. 29. He has 17 years of service with the state, most recently serving five years of a six-year term as a commissioner. Rokeberg represented the Sand Lake area of Anchorage in the Alaska House of Representatives from 1995 to 2007.

Lisankie previously served as an RCA commissioner from 2009 to 2015. Born in New York City, Lisankie settled in Alaska in 1982 after his discharge from active duty as a lieutenant in the U.S. Coast Guard. He holds a B.A. degree in economics with honors and departmental distinction from Rutgers University and a J.D. degree in law from Duke University.

Lisankie was admitted to practice law in Alaska in 1985 and focused on administrative law. As staff counsel for the non-profit Alaska Consumer Advocacy Program he represented consumers before the former Alaska Public Utilities Commission.

Lisankie has more than 20 years of state service in the Department of Law as an assistant attorney general and in the Department of Labor and Workforce Development as a hearing officer, chief of adjudications, and finally as director of the Division of Workers’ Compensation.

Between 1987 and 1989 Lisankie served on the board of directors of Chugach Electric Association Inc. He has lived in Kodiak, Juneau, and Anchorage. He was first appointed to the commission by Gov. Sarah Palin on March 2, 2009.

Alyska receives EPA diesel reduction grant

The Alaska Energy Authority received $335,024 in a grant from the U.S. Environmental Protection Agency as part of EPA’s Diesel Emissions Reduction Act program.

The EPA announced $1.3 million in grants for clean diesel projects in the Northwest and Alaska.

“Clean diesel technologies not only improve air quality, but advance innovation and support jobs,” EPA Administrator Scott Pruitt said in announcing the grants.

“By promoting clean diesel technologies, we can improve air quality and human health, advance American innovation, and support green jobs in economically disadvantaged communities, while growing our economy,” said Chris Hladick, regional administrator for EPA’s Northwest and Alaska Region.

The Diesel Emissions Reduction Act program is administered by EPA’s West Coast Collaborative, a clean air public-private partnership that leverages public and private funds to complete important diesel reduction projects that reduce emissions from the most polluting diesel sources in impacted communities in West Coast states and U.S. territories.

AEA received $335,024 and is providing $362,942 in mandatory cost share and an additional $33,220 in federal cost share for a total of $751,200. EPA said the funds will be used to complete four to six repowers and generator replacements in rural communities, addressing antiquated mechanically governed prime power diesel “genset” engines with newer, more fuel efficient Tier 2 and Tier 3 marine engines that reduce diesel emissions and save fuel, EPA said. The agency said the project is expected to reduce 4.2 tons of particulate matter, 46.6 tons of nitrogen oxides, 22.8 tons of carbon monoxide and 603 tons of carbon dioxide over the lives of the engines.

The EPA also funded programs in Idaho, Oregon and Washington, and said it has awarded nearly $12.5 million in DERA funding in West Coast states and U.S. territories in the past year.

Alyska reports another Berth 5 spill

Alyska Pipeline Service Co. has reported a spill at Berth 5 at the Valdez Marine Terminal, the second spill at that berth in six months.

The current spill was found by operations personnel during rounds the morning of Feb. 3. Alyska estimates that the spill amount is less than 200 gallons, which has spilled to containment, the Alaska Department of Environmental Conservation’s Division of Spill Prevention and Response said Feb. 4 in a situation report. The division said there was some spray to water but that no sheen on the water has been reported.

The earlier spill, which occurred in late September, was reported as an oily sheen at the Port of Valdez. For that spill Alyska estimated that fewer than 100 gallons of crude oil residue were released.

Alyska told the Prince William Sound Regional Citizens’ Advisory Council Jan. 18 that it tightened its procedure for testing loading arms after the September spill, and said it planned to replace valves in the loading arms as leakage around a valve that was a root cause of the September spill (see story in Feb. 4 issue of Petroleum News).

The company said the September incident occurred during routine testing of a ball valve designed to prevent fluids spilling from the loading arm when it is not in use. A test was begun, then deferred to later in the afternoon, but a couple of valves remained open and seawater used for testing flowed back through the seawater valve. The arm held some residual crude and Alyska estimated that some 70 gallons of oil escaped.

The division said the cause of the current spill is under investigation, “but early indicators show that crude was leaking from the end caps of two (of four) loading arms into containment.” No tankers were loading when the spill occurred.

The source is secured, the division said, and Berth 5 is boomed, with skimming vessels deployed to the site.

While there is no sheen reported on the water, the division said sensitive area protection task forces are on standby.

The division said future plans are to clean up the spill site and continue monitoring to evaluate the need to deploy additional response equipment and personnel.

Nome gets new look as possible Arctic port

F ederal officials will take another look at the historic Alaska community of Nome as a possible port serving ships heading for the Arctic.

The U.S. Army Corps of Engineers announced it has signed an agreement with the city of Nome to examine whether benefits justify costs of navigation improvements, said Bruce Sexauer, chief of civil works for the Corps’ Alaska District.

“The study will look at economic and social reasons to see if expanding the port is in the federal interest,” he said.

The study process generally takes three years and could culminate in a Corps’ recommendation to Congress to authorize port improvements, Sexauer said.

Alaska lacks deep-water ports along most of its west and northwest coast. The nearest permanent U.S. Coast Guard station is Kodiak more than 800 miles away.

Arctic marine traffic continues to grow and Nome, though south of the Arctic Circle, is well situated south of the Pacific chokepoint to the Arctic, the Bering Strait, Sexauer said.

A joint federal-state study started in 2008 looked at alternatives for Arctic ports in the Bering and Chukchi seas. Nome became the top choice because of its infrastructure already in place, including an airport that handles jets, a hospital and fuel supply facilities.

“It just needed to be bigger and deeper,” Sexauer said.

However, “economic justification for the port diminished in late 2015 when Royal Dutch Shell PLC drilled a dry hole in the Chukchi Sea and suspended its U.S. Arctic offshore drilling program,” he said.

The Corps for a moment at Nome went away, at least the oil and gas benefits,” Sexauer said. The Corps paused its study with the state and officially terminated it last month, Sexauer said.

The study with the city will again look at how a Nome port would aid marine traffic for petroleum development, mining and regional delivery of fuel and other products.

Federal law changed in 2016 to allow the Corps to also consider social benefits, such as support of search and rescue operations, national security and aid to communities to help them be sustainable.

The Port of Nome remains too shallow to handle large ships. Fuel tankers stay anchored in deep water and fuel is lightered to Nome.

Nome’s inner harbor in 2014 was just 10 feet deep and its outer harbor was less than 23 feet deep. The Corps that year looked at constructing docks up to 1,000 feet long and dredging to 35 feet.

The Corps has scheduled a planning meeting in Nome in late April to detail the scope of the new study.
I
n two separate lawsuits filed in the federal District Court in Alaska, environmental organizations have challenged the legality of the Bureau of Land Management’s December oil and gas lease sale for the National Petroleum Reserve-Alaska. In the lease sale ConocoPhillips and Anadarko Petroleum expanded their lease holdings in the northeastern part of the reserve.

The Northern Alaska Environmental Center, the Alaska Wilderness League, the Defenders of Wildlife, the Sierra Club and the Wilderness Society filed one appeal, while the Natural Resource Defense Council, the Center for Biological Diversity, Greenpeace and the Friends of the Earth filed the other.

Both lawsuits challenge the legitimacy of the lease sale on the grounds that the sale contravened the National Environmental Policy Act, because BLM did not carry out an assessment of the potential environmental impacts of the sale prior to conducting the sale. Under the terms of NEPA, any significant federal action that could impact the environment requires an environmental evaluation, potentially leading to a formal environmental assessment or the development of an environmental impact statement.

**Integrated activity plan**

The lawsuits accept that the land tracts offered for lease in the sale were available for leasing under an Integrated Activity Plan developed in 2013 for the reserve. That IAP was vetted through an environmental impact statement, the result of which was the exclusion of much of the northern part of the reserve from industrial development, including the biologically sensitive Teshekpuk Lake.

But the conducting of a lease sale is, in itself, a significant federal action, warranting a NEPA review, the lawsuits say. Since the publication of the IAP, BLM has conducted annual NPR-A lease sales without any additional environmental assessment or environmental impact statement but limiting land tracts on offer to those allowed under the terms of the IAP. The agency apparently determined that the environmental assessment associated with the IAP was sufficient for the lease sales, and that no new information had come available to alter that assessment.

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OIL PATCH INSIDER

refiners.

“Shipments from U.S. ports have increased from a little more than 100,000 barrels a day in 2013 to 1.53 million in November, traveling as far as China and the U.K.,” the news agency said in the article.

According to the Census Bureau, the U.S. exported about 700,000 barrels of light domestic crude in December to the U.A.E., which the Energy Information Administration indicates is the fourth-largest OPEC producer.

The region’s first cargo of U.S. oil, per Abu Dhabi National Oil Co., or ADNOC, the U.A.E.’s state-owned oil company, was purchased in July for September delivery.

The Middle Eastern country imports extra-light oil to process in a unit known as a splitter. Normally the U.A.E. relies on Qatar for its condensate, but due to a political dispute the country decided in June to ban all petroleum ships from Qatar.

ANWR’s proposed natural gas line to Kaktovik

Did you know a 7-inch, 23-mile natural gas line was once proposed by KIC well operator Chevron to a power plant it wanted to build in the village of Kaktovik within the 1002 area of ANWR? At least that’s the rumor.

The plant would supply the village with inexpensive natural gas for power and Kaktovik could then sell power to a field development supposedly planned by Chevron at the time.

A request for proposals, or RFPs, allegedly went out for the gas line and power plant in a very private offering before the drilling rig came off the KIC well, the only well ever drilled in ANWR.

Rumor has it the power plant would prevent the U.S. Environmental Protection Agency, or EPA, from hinder- ing field development because of air quality concerns, a ripe source for lawsuits by environmentalists.

Again rumors (not confirmed) say Chevron wanted to proceed with the gas line and the power plant to begin a legal battle against the plan. (The companies were 50-50 partners in the Arctic National Wildlife Refuge coastal plain (1002) area leases.)

The only leased acreage in the 1002 area, thought to be highly prospective for oil and gas, is on 92,000 acres of private land — the Native regional corporation for northern Alaska, Arctic Slope Regional Corp., owns the subsurface oil and gas mineral rights and the local village corporation, Kaktovik Inupiat Corp., owns the surface.

The KIC well, drilled by Chevron in the winters of 1985 and 1986, is considered the tightest hole in the world. The well test results are still confidential.

A development plan involving several wells within the Chevron-BP leases was reportedly filed with the feds and then pulled a few days later in hopes a lease sale for federal land in the 1002 area would be held in the near future. (Once a development was declared by public companies Chevron and BP would have had to reveal the KIC well results to stockholders and analysts, which could lead to stiff competition in a lease sale.)

Speaking of an ANWR 1002 lease sale, as previously reported in PN, there are two areawide lease sales planned by the Trump administration in the next 10 years, with the first sale taking place within four years and the second within seven years of this past December.

Alaska gas upside down

Whereas crude oil is much more valuable than natural gas and can often bear the cost of long-distance transport, natural gas is most economically produced and used in the same area.

But in Alaska, Fairbanks Interior Gas Utility, or IGU, is doing a deal to buy Hilcorp natural gas from the Cook Inlet basin to liquify and then ship north by truck where the LNG is converted back to natural gas for commercial and residential use. IGU is waiting on what is likely to be Doyon’s last, and successful, well in the nearby Nenana basin.

At the same time Nutrien, the owner of the Nikiski/North Kenai fertilizer facility that employs 400 well-paid, full-time, workers when in full operation, is looking for local gas. (The facility, owned by Nutrien predecessor Agrium, closed in 2007 when it could not get enough natural gas feedstock to operate.)

Can the Nutrien facility afford to ship gas from Nenana if the Fairbanks operation gobbles up all the excess gas in the Cook Inlet basin? PN’s reliable sources say, “no way.”

State subsidies and loans can help, and there are some in place, but should Alaskans use state funds to subsidize such a lop-sided arrangement?

Here’s to wishing there was an easy answer....

continued from page 1

LNG FACILITY

continued from page 1

By Phillips Petroleum and Marathon Oil in 1969 to provide a means of monetizing excess natural gas coming from the Cook Inlet basin. And over the years the plant produced LNG for delivery by tanker to Japan. However, more recently, as gas supplies from Cook Inlet tightened and the price of Cook Inlet gas increased while global LNG prices have fallen, the export of LNG from Nikiski slowed to a halt. There were just five cargoes exported in 2014 and six in 2015. Exports stopped entirely in 2016.

ConocoPhillips put the Nikiski LNG plant up for sale in November 2016.

—ALAN BAILEY

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—KAY CASHMAN

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LEASE SALE

With ConocoPhillips using the sales to expand its area of operations in the reserve, moving closer to Teshekpuk Lake, the conducting of the recent lease sale did require formal NEPA analysis, to evaluate the potential impact of the evolving industrial development in the region, the lawsuits argue. One lawsuit asks that the court declare the 2017 lease sale unlawful, with all leases purchased in the lease sale cancelled. The other lawsuit requests the same court action for both the 2016 and 2017 sales.

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ANADARKO IN ALASKA

Discovery of Alpine

Anadarko also partnered with ARCO Alaska Inc. (subsequently ConocoPhillips Alaska Inc.) in an exploration venture that led to the discovery of the Alpine oil field in 1994 in the western North Slope. Alpine was declared commercial in 1996 and subsequently went into production with ARCO as operator and Anadarko as a working interest owner.

The two companies subsequently embarked on a joint exploration campaign in the northeastern sector of the National Petroleum Reserve-Alaska.

But Anadarko, anxious to also control its own acreage, acquired its own North Slope leases in state lands in 1998, as well as signing an exploration agreement for Arctic Slope Regional Corp. land in the Brooks Range foothills. In 1996 Anadarko also entered the Cook Inlet oil and gas industry, partnering with ARCO in exploration acreage in this region. However, in 2002 the company sold all its Cook Inlet leaseholdings to Aurora Gas, a small, local natural gas producer.

In 2005 Petro-Canada formed a joint exploration agreement with Anadarko for Foothills gas exploration but the partners held off exploration drilling, pending a gas line development decision. In 2006 Anadarko pioneered a new design of seismic vehicle for seismic surveying in the region.

In the winters of 2002 and 2003 Anadarko conducted a new concept for a portable Arctic drilling platform, drilling into a shallow methane hydrate deposit under the North Slope, in a project termed “Hot Ice.” That particular project did not work out. But, by that time, Anadarko had more acreage under lease north of the Brooks Range than any other operator. The company had also operated an exploration well, the Altamaha No. 1 well, in NPR-A. And the company’s partnership with ARCO was paying off, with discoveries such as Spark, Mooses Tooth, Lookout and Rendezvous in the NPR-A, ultimately leading to partnership with ConocoPhillips in the CD-5 and Moosies Tooth developments. The discovery of Alpine satellite fields was driving an expansion of the Alpine field facilities.

BP OUTLOOK

make North Slope gas, currently a stranded asset, a more commercially viable asset, a more commercially viable make North Slope gas, currently a stranded asset, a more commercially viable make North Slope gas, currently a stranded asset, a more commercially viable make North Slope gas, currently a stranded asset, a more commercially viable make North Slope gas, currently a stranded asset, a more commercially viable make North Slope gas, currently a stranded asset, a more commercially viable make North Slope gas, currently a stranded asset, a more commercially viable make North Slope gas, currently a stranded asset, a more commercially viable make North Slope gas, currently a stranded asset, a more commercially viable approach to an increasing emphasis on the rate of demand growth will slow in economies, especially India and China. But planned investment and a focus on cost. That is fit for a changing world; and growing conducting safe, reliable and efficient operations. Addressing safety by these means brings the added benefits of lower operating costs and improved business performance. BP achieved an operational reliability level of 95 percent across its upstream and downstream businesses in 2017, Dudley said. The company has also been simplifying its work processes, creating an environment where people feel empowered to adapt and hence improve performance, he said.

Distinctive portfolio

In terms of maintaining a distinctive portfolio, BP has been evolving its business to enable flexibility in a changing world. In the upstream the company has been growing its natural gas portfolio while focusing on what it refers to as “advantaged oil,” oil resources that are low cost or high margin to produce. Including the company’s equity share production in Russia, where the company is producing about 3.6 million barrels of oil equivalent per day and has estimated reserves of 18.4 billion barrels of oil equivalent. The company currently has 13.7 years of reserve life, Dudley said. In Russia, BP has a 19.75 percent shareholding in Rosneft and also has interests in three joint ventures.

In terms of energy diversity, the company has been moving back into the solar energy industry and now manages about 2 gigawatts of solar capacity. The company’s downstream business is also strong and well differentiated, with strong brands, an increasing exposure to growth markets and geographically balanced refining, Dudley said.

Growing returns

When it comes to growing returns, the third prong of BP’s business strategy, the company is striving to simplify its business and reduce its costs, without compromising on safety, Dudley said. The company is also maintaining a tight discipline in its capital investments, setting strict investment hurdles in terms of required rates of return. Another strategy is to seek ways of optimizing the company’s portfolio by, for example, the merger of some assets with other companies. Beneficial partnerships with complementary businesses can also reduce costs.

BP has been seeing its strategy start to deliver results. The company’s return on capital employed doubled to 5.8 percent in 2017 and is expected to exceed 10 percent by 2021, Dudley said.

Also in 2007, the passage of the Alaska Gasline Inducement Act under the administration of Gov. Sarah Palin encouraged Anadarko to move forward with the drilling of gas exploration wells in the Foothills region, in particular near Utmiak. A proposal for a gas “bullet line” from the North Slope to Southcentral Alaska also motivated this exploration effort.

Other interests

By 2011 Anadarko appeared to be showing more interest in ventures outside of Alaska, including shale oil and gas in the Lower 48. The company had found gas in four exploration wells in its Foothills program. But the emerging shale gas industry in the Lower 48 was undermining the economics of the Alaska gas line concept. Ultimately Anadarko’s Alaska gas exploration came to a halt.

Since then Anadarko’s Alaska leaseholdings have shrunk, with, until now, the company retaining just its ownership interest in leases it has held jointly with ConocoPhillips.
CONOCO UPBEAT

tion costs in Alaska, Lance commented that ConocoPhillips has succeeded in reducing the cost of supply from its Alaska assets and sees its production in the state as flat to growing in the coming years.

“Alaska’s been one of our legacy areas for a long time for the company,” Lance said. “Alaska’s made some tremendous progress in lowering the cost of supply for the base business up there, as well as when we look at the opportunity set for investments to grow and develop. So, despite us being in Alaska for 40 years and the largest producer up there, we still see a lot of opportunity.”

Opportunities in Alaska

Questioned about what appears to be a bargain price for the Anadarko assets, Lance commented that, while ConocoPhillips sees continuing opportunities in Alaska, Anadarko has different priorities. With more than a million acres under lease, ConocoPhillips sees much prospectivity, Lance said, adding that his company has scheduled a seismic survey using its new high-resolution compressive seismic technique for this winter.

“So there’s a lot of interesting things that we see as upside that are core to us,” Lance said. “I think for Anadarko it just wasn’t a core asset for them, so just a little different view of the property.”

Lance characterized the deal with Anadarko as a “bolt-on” opportunistic purchase, rather than a signal of expanding capital investment. ConocoPhillips is sticking with its base strategy, making a continuing oil price assumption of about $50 per barrel for West Texas Intermediate, and with an annual capital expenditure program of some $5.5 billion.

ConocoPhillips’ 100 percent ownership of the western North Slope assets will result in access to about 200 million barrels of gross reserves and about 900 million barrels of risked, gross resource, said Al Hirshberg, ConocoPhillips executive vice president for drilling and projects.

Exceptional year

Reflecting on ConocoPhillips overall global performance, Hirshberg commented that 2017 had been an exceptional year operationally.

“We had our best year ever on safety and environmental performance, while delivering 3 percent underlying production growth for $4.6 billion of capital,” Hirshberg said.

The company as a whole saw an increase in earnings to $740 million in 2017 from a loss of $3.3 billion in 2016, with the increase in earnings primarily resulting from rising oil prices coupled with higher production volumes, partly offset by higher production costs, said Don Wallace, ConocoPhillips chief financial officer and executive vice president for finance and commercial.


“ConocoPhillips Alaska’s realized oil price in the fourth quarter averaged $61 per barrel, up from $51 per barrel in the third quarter of 2017,” ConocoPhillips Alaska spokeswoman Amy Burnett has told Petroleum News. Moreover, despite the low oil price environment, ConocoPhillips Alaska’s liquids production on the North Slope increased by 3.4 percent in 2017 relative to 2016, primarily because of investments made since the passage of the Senate Bill 21 tax legislation, Burnett said.

During the earnings call Hirshberg commented that the 1H NEWS development in the Kuparuk River unit achieved first oil in November.

Core investments

Wallace commented that unconventional oil and gas together with development in Alaska remain core to ConocoPhillips’ capital program. The new lower U.S. tax rate and improved capital recovery will enhance the attractiveness of these investment programs, he said.

Hirshberg said ConocoPhillips expects to bring its Greater Mooses Tooth 1 development in the National Petroleum Reserve-Alaska online this year, as well as progressing Alaska exploration opportunities. The company has been permitting five exploration wells for drilling this winter. In the Lower 48 unconventional production saw a dip in 2017 but rebounded later in the year. ConocoPhillips acquired an additional 245,000 acres of unconventional exploration leases in the Lower 48 in the fourth quarter of 2017.

However, Wallace emphasized that ConocoPhillips will not become overly excited about the current higher oil price. There is much volatility in the market and it has only been 50 or 60 days since Brent crude broke through $60 per barrel, he said. ConocoPhillips is sticking with its $50 oil price discipline, with any buildup of surplus cash going into increased shareholder dividends and share buy backs, he said.

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