Petroleum news

page 2 EIA forecasts record US crude volumes this year, lower prices

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Feds might not allow Conoco to operate Prudhoe Bay; Gil Mull and Richfield at Katalla

AS THE THREE MAIN OWNERS of the Prudhoe Bay oil field hash out who will operate the unit when the deal between BP and Hilcorp closes in 2020, their conversations undoubtedly involve concerns about federal and state approval of Hilcorp's acquisition of BP Exploration (Alaska) and its assets, especially if ConocoPhillips elects to operate all or part of the Prudhoe unit. (See story in the Sept. 8 edition of Petroleum News, titled Prudhoe operator? ConocoPhillips … and Hilcorp … in talks about operatorship.)

The deal will result in the ownership of the state's main producing oil field, Prudhoe Bay, split three ways, with Conoco holding 36% working interest, ExxonMobil 36% and Hilcorp 26%.

see **INSIDER** page 11

Changing of the guard on North Slope; no longer a mature basin

The $5.6 billion sale of BP's Alaska business to Hilcorp demonstrates a growing trend and the differing strategies of the majors and private oil and gas players, industry observers say.

JUDY PATRICK

GREG LALICKER

"BP was a pioneer in Alaskan drilling and one of the key players in building the Alaskan oil industry, including drilling … for the massive Prudhoe Bay field in the 1960s and participating in the Trans Alaska Pipeline in the 1970s," Enverus' senior M&A analyst Andrew Dittmar was quoted as saying in press reports. "Their exit and replacement by Hilcorp marks a changing of the guard for the Alaskan petroleum industry."

"In departing Alaska, BP is choosing to focus on higher growth opportunities elsewhere, including in U.S. unconventionals," Dittmar said. "The company made a major commitment to growth in U.S. shale by acquiring Permian, Eagle

see **ANS CHANGES** page 12

XCD IDs 1st lead in Peregrine project; Ferguson's take on BP-Hilcorp deal

Alaska-focused oil junior XCD Energy said Sept. 10 that it has identified the first lead within its wholly owned Peregrine project, which is west of the central North Slope on 149,590 acres.

DOUGAL FERGUSON

The acreage is on the same Nanushuk oil trend as ConocoPhillips' big Willow discoveries about 22 miles to the north.

An "internal estimate," for its Merlin prospect lead "calculating a best-estimate unrisked recoverable prospective resource" is 255 million barrels of oil, Perth, Australia independent XCD says.

According to the ASX-listed company, Merlin is the first of many leads mapped within XCD's National Petroleum Reserve-Alaska lease area south of Willow.

This best estimate is "based on a calculated 1.112 billion barrels of original oil-in-place with a 23% recovery factor," the company says.

The low to high recoverable resource estimates range from 59 million barrels to 1.2 billion barrels, XCD says.

see **XCD ENERGY** page 10

NATURAL GAS

54 tcf possible

USGS estimates undiscovered, recoverable gas trapped in North Slope hydrates

By KAY CASHMAN
Petroleum News

An estimated 53.8 trillion cubic feet of undiscovered, technically recoverable natural gas is trapped within methane gas hydrate formations in Alaska's North Slope, the U.S. Geological Survey says in a new geology-based assessment released Sept. 10.

The area assessed extends from the National Petroleum Reserve-Alaska on the west through the Arctic National Wildlife Refuge on the east and from the Brooks Range northward to the state-federal offshore boundary, 3 miles north of the coast-

see **GAS HYDRATES** page 14

HELEN GIBBONS/USGS

In 2010, the U.S. Geological Survey recovered white chunks of gas hydrate (methane ice) mixed with gray sediment a few feet below the seafloor in the Arctic Ocean at a water depth of approximately 8,000 feet.

LAND & LEASING

Expanded sale?

State looks at adding exploration license area to Cook Inlet areawide

By KRISTEN NELSON
Petroleum News

The Alaska Department of Natural Resources' Division of Oil and Gas has a request out for substantial new information for its 2020 Cook Inlet and Alaska Peninsula areawide oil and gas lease sales.

The Alaska Peninsula rarely draws interest and typically there would be limited interest in Cook Inlet because so much of the prospective acreage in that area has already been leased.

But the division said it is considering augmenting the Cook Inlet sale area by including the Southwest Cook Inlet exploration license area, opening up acreage on the southwest side of the inlet for leasing.

> *The earliest exploration wells in Cook Inlet were drilled near Oil Bay and the Week Creek oil seeps by the Alaska Petroleum Co., beginning in 1902.*

The division received a proposal for a Southwest Cook Inlet exploration license in April 2013; when it asked for comments and competing proposals it received a competing proposal. The division prepared a written finding and, because there were competing bids, held a sealed bid open-

see **EXPANDED SALE** page 13

PIPELINES & DOWNSTREAM

The unending legal fight

Court gives First Nations another chance to show they've not been fully consulted

By GARY PARK
For Petroleum News

The legal roller-coaster ride by the Trans Mountain pipeline expansion project, TMX, has taken another downward lurch.

Canada's Federal Court of Appeal has allowed an extension of legal challenges by six First Nations along the pipeline right of way against the latest re-approval of the project.

They continue to make a case that the government of Prime Minister Justin Trudeau has failed to properly consult them.

But the court denied six other applications focused on the potentially negative environmental impacts of TMX, especially to whale populations off the British Columbia coast, ruling those challenges were just attempts to re-litigate previous court cases.

> *Justice David Stratas said in his written judgment that the "duty to consult does not require the consent ... of First Nations and Indigenous peoples before projects like (Trans Mountain) can proceed."*

Consult not consent

Justice David Stratas said in his written judgment that the "duty to consult does not require the

see **LEGAL FIGHT** page 12

● FINANCE & ECONOMY

EIA short term: production up, prices down

Record US crude volumes this year and next, agency says, with prices down from last forecast on falling global liquids consumption

By KRISTEN NELSON

Petroleum News

The U.S. Energy Information Administration said in its September Short-Term Energy Outlook, released Sept. 10, that Brent crude oil spot prices averaged $59 per barrel in August, down $5 from July and down $13 per barrel from August 2013, leading EIA to reduce its 2019 Brent forecast to $63 per barrel, down $2 from the August forecast, with Brent expected to average $60 in the fourth quarter.

The 2020 Brent price is now forecast at $62 per barrel, $3 lower than the agency's August forecast.

"Average spot prices for Brent crude oil in August were slightly below $60 per barrel," said EIA Administrator Dr. Linda Capuano. "The August price reflects a decrease of nearly $5 per barrel from July and more than $13 per barrel compared with last year. This month's forecast is that Brent spot prices will average about $60 per barrel during the fourth quarter of this year, followed by prices that will range in the low $60s per barrel through the end of 2020," she said.

LINDA CAPUANO

Part of the lower price forecast is due to lower global oil demand growth, which the agency said it has reduced to 900,000 barrels per day this year, down 100,000 bpd from the August forecast. EIA also attributed the drop to "recent global crude oil price fluctuations."

If 900,000 bpd is the average growth for the year, EIA said it would be the first time since 2011 that growth was less than 1 million bpd.

West Texas Intermediate

EIA said it expects West Texas Intermediate to average $5.50 per barrel less than Brent next year, with the spread between Brent and WTI narrowing. The price spread was $3.60 on Aug. 19, the agency said, the narrowest since March 2018.

"Crude oil prices in the Permian region increased during this period with the addition of two pipelines mid-month that reduced takeaway constraints to the U.S. Gulf Coast," EIA said. An estimated 670,000 bpd were added by the Cactus II crude oil pipeline and the repurposing of the EPIC Midstream from natural gas liquids to crude added about

see EIA OUTLOOK page 6

contents

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● FINANCE & ECONOMY

Whither the North Slope crude price?

ANS crude holds pricing edge on WTI and Brent prices, for now; state forecasts call ANS prices in $60 range, but Saudis seek $80

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude oil prices closed at $64.30, up 25 cents on the day Sept. 10, while other major crude indicators fell.

The Brent price was $62.38, down 21 cents, while West Texas Intermediate fell 45 cents, to $57.40. Henry Hub natural gas price at close was $2.58, off a single penny.

On the same day, Alaska North Slope production was 432,742 barrels. The extra 25 cents per barrel added $108,185.50 to the value of the day's shipment, for a total day's value of $27,825,310.60 at closing prices.

Alaska and its oil industry are sustained in large measure by the daily flow of oil through the trans-Alaska oil pipeline. Many Alaskans hope that oil prices will rise, which of course would make the state's daily production all the more valuable.

The state, and other organizations attempt to forecast oil and gas prices, in order to project the state's anticipated tax and royalty income.

Consistently, the price projections are off, sometimes by quite a lot, and assumptions must be adjusted to market realities.

ANS crude holds premium

Recently, ANS crude has been selling for more than WTI and Brent, but that has not always been the case.

In 2011, in a much richer oil pricing scenario, ANS crude prices gained a premium over WTI.

The March 23, 2011, price of ANS was $117.55, a $12.35 premium over WTI at $105.20, according to the Alaska Department of Revenue Tax Division.

Someday, perhaps the price of oil will climb again to 2011 levels.

At $117.55 per barrel, the Sept. 10, 2019, day's production would have been valued at more than $50 million, at the March 23, 2011, closing price.

In those days, ANS and WTI prices ranged much closer together, with WTI often commanding a small premium.

Pricing swings between ANS prices and WTI, or Brent, are likely attributed to fluctuations in the WTI or Brent, rather than fluctuations in ANS prices, which are held stable by a small, relatively stable market.

North Slope oil is delivered aboard tankers primarily to West Coast refineries. It competes on the spot market with other crudes that can be hauled in by water.

The market for ANS crude is very shallow; transactions are infrequent, and the few sellers are not involved in constant or frequent trading. Days go by without a spot market deal for ANS crude, the Department of Revenue told Petroleum News in 2011.

In 2011, often the light, sweet WTI crude was worth a couple of dollars per barrel more than ANS, which is a little heavier and more sour — containing more sulfur, which requires more refining.

The state looks ahead

In its Spring 2019 forecast, the Alaska Department of Revenue's Alaska North Slope oil prices were forecast to average $68.90 per barrel for FY 2019 and $66.00 for FY 2020.

Based on a review of oil market fundamentals, the department said it chose not to revise its view on long term oil price since the fall forecast, adding that long term, it expects oil prices to stabilize in the low 60s in inflation-adjusted dollars.

The Spring 2019 forecast reflects a markedly lower price than recent previous state projections.

A fall forecast by former Gov. Bill Walker foresaw an average Alaska oil price of $75 per barrel for fiscal year 2020, with prices climbing to an average of $84 per barrel by 2027.

The Department of Revenue production forecast — prepared in collaboration with the Department of Natural Resources — projected North Slope oil production averaging 511,500 barrels per day in FY 2019 and 529,500 barrels per day in FY 2020.

The update slightly adjusted production expectations for the next several years, the department said. Production is expected to remain around 500,000 barrels per day over the next decade as new developments offset production declines from existing fields.

see **ANS CRUDE PRICE** *page 8*

Petroleum news

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Congratulations

Congratulations Hilcorp!

A round of applause to David Wilkins and all the folks at Hilcorp Alaska on the acquisition of all BP's assets in Alaska.

Hilcorp Energy Company

David Wilkins, senior vice president, Hilcorp Alaska

ABR Inc.
Acuren
AES Electric Supply, Inc
Afognak Leasing LLC
Ahtna, Inc.
Airgas, an Air Liquide company
AK Lofts
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Alaska Railroad
Alaska Rubber & Rigging Supply Inc.
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Resource Development Council
SALA Remote Medics
Security Aviation
Solar Turbines Incorporated
Soloy Helicopters
Sourdough Express
Strategic Action Associates
Summit ESP, A Halliburton Service
Tanks-A-Lot
The Local Pages
Thompson Metal Fab, Inc.
TOTE – Totem Ocean Trailer Express
Udelhoven Oilfield System Services Inc.
Weston Solutions
Wolfpack Land Co.
Worley

FINANCE & ECONOMY

Crescent Point sheds assets, targets debt

Crescent Point Energy is beating a hasty retreat from its glory days when it was Canada's 12th largest oil and gas producer, with major holdings in Saskatchewan and Utah.

Now faced with wrestling down a net debt that peaked at C$4.4 billion last year, it launched a bold turnaround strategy when Craig Bryksa took over the helm from long-time Chief Executive Officer Scott Saxberg and has so far generated asset sales of C$1.3 billion.

The biggest in that process occurred Sept. 3 when two bundles of assets (C$700 million for 20,000 barrels of oil equivalent per day of production in the Uinta Basin of Utah and the balance for 7,000 boe per day in Saskatchewan) were sold to multiple unnamed buyers for C$912 million, freeing Crescent Point to focus on its core oil properties.

The announcement "is the latest example of significant changes our team has implemented within a short period of time that supports our strategy to focus our asset base and improve our overall efficiencies," Bryksa told analysts.

"I think we have made significant strikes in getting our balance sheet where we want it to be," he said of the company's goal to reduce its net debt to C$2.75 billion by the end of 2019.

Bryksa said Crescent Point's hope is to pursue additional asset sales, including adjustments to its Saskatchewan conventional oil assets that require specialized drilling and secondary recovery methods to force light oil to the surface.

The company now expects capital spending will be unchanged this year at about C$1.3 billion, while it plans to buy back some shares from investors.

Eight Capital analyst Adam Gill said the Crescent Point leadership has finally "got something done," adding that the value of the transactions was reasonable given the current difficulty of reaching deals in Canada.

The challenge was reflected by oil sands producer Cenovus Energy, when it pulled an asset package off the market earlier this year after offers fell short of its objective.

—GARY PARK

GOVERNMENT

BLM extends Willow comment period

The federal Bureau of Land Management said Sept. 6 that it has extended the public comment period for the draft environmental impact statement on the Willow master development plan from 45 to 60 days. The deadline was previously Oct. 15; it is now Oct. 29. BLM said the extension was provided to allow additional time for North Slope communities to focus on subsistence activities.

The agency also said it was updating its public meeting schedule to add details for the Oct. 2 Nuiqsut gathering, which is from 5-8 p.m. at the Kisik Center. BLM said the meeting will include a subsistence hearing in compliance with Section 810 of the Alaska National Interests Lands Conservation Act.

The public meetings were scheduled to begin Sept. 9 in Fairbanks, move to Anaktuvuk Pass Sept. 10 and to Anchorage Sept. 12.

Meetings later in September and in October include:

• Utqiagvik, Sept. 18, 6-8 p.m., Inupiat Heritage Center;
• Atqasuk, Sept. 19, 6:30-8:30 p.m., Atqasuk Community Center; and
• Nuiqsut, Oct. 2, 5-8 p.m., Kisik Community Center.

—PETROLEUM NEWS

continued from page 2

EIA OUTLOOK

400,000 bpd of capacity.

This reduced the need for crude oil to transit through Cushing, "lowering the cost of transportation to refineries and export terminals on the U.S. Gulf Coast," the agency said, with Cushing stock dropping by 10 million barrels from the third week in July to Aug. 23.

EIA said it expects the spread to widen slightly as regional markets rebalance "and the spread settles closer to the new pipelines' tariff from the Permian Basin to the Gulf Coast."

US production

"EIA's September Short-Term Energy Outlook continues to forecast record U.S. crude oil production in 2019 and 2020," Capuano said. "Largely driven by growth in the Permian region in Texas and New Mexico, U.S. production has risen above 12 million barrels per day since January 2019. EIA forecasts U.S. oil production to average 12.2 million barrels per day in 2018, before exceeding 13 million barrels per day in 2020," she said.

The EIA forecast of 12.2 million bpd this year is up by 1.2 million bpd from the 2018 level, the agency said.

The increase slows to a rise of 1 million bpd in 2020, reflecting "relatively flat crude oil price levels and slowing growth in well-level productivity," the agency said.

Natural gas

"EIA expects Henry Hub spot prices for natural gas to remain below $2.50 per million British thermal units during the fourth quarter of 2019, as U.S. production remains on pace for another record year," Capuano said. "The September Short-Term Energy Outlook forecasts that prices will rise slightly into 2020, averaging $2.55 per million British thermal units for the year," she said.

EIA said Henry Hub averaged $2.22 per million Btu in August, down 15 cents from July.

"This summer, prices have declined amid rising natural gas production, despite high levels of both natural gas exports and consumption in the electricity generation sector," the agency said.

EIS said its assessment is that natural gas production will meet expected demand and export levels at lower price levels, so it has lowered its Henry Hub forecast for 2020 to $2.55 per million Btu, down 20 cents from the August forecast.

U.S. dry natural gas production is forecast to average 91.4 billion cubic feet per day this year, up 8 bcf per day from last year, the agency said, adding that it expects monthly production to grow this year "and then decline slightly during the first quarter of 2020 as the lagged effect of low prices in the second half of 2019 reduces natural gas directed drilling."

Growth is forecast to resume in the second quarter of 2020, and natural gas production next year is expected to average 93.2 bcf per day.

The agency said growth in liquefied natural gas exports is expected to continue. LNG exports were estimated at 3.9 bcf per day in August and are expected to average 6.4 bcf per day next year. EIA said it "expects that continued growth of LNG exports combined with flattening production will provide support for natural gas prices through the forecast." ●

Contact Kristen Nelson at knelson@petroleumnews.com

● GOVERNMENT

Alberta facing deep cuts, big fights

Review calls for province to swallow some bitter medicine to rescue ailing finances, tied to spending with low resource revenues

By GARY PARK

For Petroleum News

For a brief few years from 2004, Alberta was an object of both envy and exasperation for the rest of Canada as it proudly and loudly proclaimed its debt-free status, 10 years after setting a goal to wipe out a C$23 billion burden.

The target was largely achieved through an unmatched gusher of oil and natural gas revenues.

Then the pressure mounted on successive governments to free up more of those riches for public services, disregarding Alberta's legislated commitment to never again fall back into debt.

The upshot over the past four years, amid sickly commodity prices, has been a rapid growth in budgetary burdens, with the net debt soaring from C$13 billion to C$60 billion, putting the province on track to hit C$102 billion in 2023.

> *The panel's mandate forbid it from building any calculations around a provincial sales tax in Alberta, which refuses to budge from its treasured status of being the only one of 10 Canadian provinces without such a tax.*

Panel probes financial challenges

Recently elected Premier Jason Kenney has let it be known that will not happen during his watch.

He campaigned last spring on a consistent message that Alberta "is drowning in debt," a line that apparently resonated with voters who gave him a thumping majority.

On taking power he named a panel led by Janice MacKinnon, a former finance minister in Saskatchewan under a left-wing New Democratic Party government, to probe his province's financial challenges.

The findings were released Sept. 2 with a blunt opening line that Alberta "faces a critical financial situation that demands decisive action. At the same time, this is an opportunity for the province to look beyond just short-term quick fixes to reduce spending."

The panel seemed to view its priority as delivering a harsh assessment of Alberta's outlook along with a stark warning that the province is unlikely to ever again see oil prices climb above US$100 a barrel or gas recapture its peak of about C$16 per thousand cubic feet.

Resource revenues key

"What typically happens in Alberta is that, when natural resource revenues go up, so does spending. But the reverse doesn't happen," said the report entitled a Blue Ribbon Panel on Alberta's Finances.

> *"What typically happens in Alberta is that, when natural resource revenues go up, so does spending. But the reverse doesn't happen," said the report entitled a Blue Ribbon Panel on Alberta's Finances.*

By failing to reduce spending in step with sharp declines in resource revenues "this exacerbates the structural imbalance between revenue and expenses and leads to rapid increases in the province's debt and eventually necessitates painful fiscal adjustments," the panel said.

One of the most telling statistical tables, covering Canada's four largest provinces, showed per capita spending in 2017 was C$13,819 in Alberta, C$13,539 in Quebec, C$10,825 in British Columbia and C$10,281 in Ontario, while the average for all nine provinces (excluding Alberta) was C$11,368.

The conclusion was that if Alberta lowered its annual spending to C$40 billion from the current C$50 billion and simply matched the average spending of the "big three," Alberta would not have a deficit. In fact it would have a budget surplus this year of almost C$4 billion.

Without a "course correction," the panel estimates Alberta will see the interest on its debt soar to C$3.7 billion a year from C$1.9 billion.

Sales tax not in study

The panel's mandate forbid it from building any calculations around a provincial sales tax in Alberta, which refuses to budge from its treasured status of being the only one of 10 Canadian provinces without such a tax.

That leaves little choice but to embark on a drastic austerity program through spending cuts that will be announced in the Kenney government first budget expected in late October.

The most obvious targets are health care, education and the public sector that will put the government at loggerheads with unions and cold involve a showdown over wage restraint legislation.

Kenney's Blue Ribbon Panel delivered a concise message. "Procrastinating will only worsen the problem, make the choices more difficult, and delay the time when Albertans can reap the benefits of balancing the budget. Raising taxes is not the answer," it said. ●

Contact Gary Park through publisher@petroleumnews.com

EXPLORATION & PRODUCTION

Drop in rigs continues, count down six

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. continues to drop, down by six the week ending Sept. 6 to 898, following a drop of 12 the week ending Aug. 30.

In its weekly rig count, the Houston oilfield services company said the active rig count was down 150 from 1,048 active rigs a year ago.

> *The company reported that 738 rigs targeted oil (down four from the previous week; down 122 from a year ago) and 160 targeted natural gas (down two from the previous week; down 26 from a year ago). There were no miscellaneous rigs active.*

The company reported that 738 rigs targeted oil (down four from the previous week; down 122 from a year ago) and 160 targeted natural gas (down two from the previous week; down 26 from a year ago). There were no miscellaneous rigs active.

The company said 67 of the U.S. holes were directional, 783 were horizontal and 48 were vertical.

North Dakota was the only state with an increase in rigs active from the previous week, up by three.

Rig counts in the majority of states were unchanged from the previous week: California, Colorado, Louisiana, New Mexico, Ohio, Pennsylvania, Utah, West Virginia and Wyoming.

Alaska was down by one rig and Texas, with the most active rigs at 438, was down by three, while Oklahoma was down by five.

Baker Hughes shows Alaska with eight rigs active for the week ending Sept. 6, up from six a year ago.

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

Baker Hughes said Sept. 9 that the August international rig count (which excludes North America) was 1,138, down 24 from 1,162 in the July count, but up 130 from 1,008 in August 2018. The land count was 894, and the offshore count 244.

The U.S. count averaged 926 for August, Baker Hughes said, down 29 from 955 in July and down 124 from 1,050 in August 2018. In Canada the count averaged 142 in August, up 21 from 121 in July, but down 78 from 220 in August 2018.

Worldwide, the rig count was 2,206 in August (1,933 land, 273 offshore), down 32 from 2,238 in July and down 72 from 2,278 in August 2018.

—KRISTEN NELSON

LAND & LEASING

Next step for ANS Guitar unit is Superior Court, says DNR commissioner Feige

As previously reported in Petroleum News, one of the two Guitar unit defaults issued by the Alaska Department of Natural Resources' Division of Oil and Gas was cured by an Aug. 19 decision of DNR Commissioner Corri Feige.

However, the second default, issued Feb. 7 for failure to meet work commitments — specifically, to spud a well on one of three Guitar leases by March 31 — was not cured.

On Sept. 4, Samuel Nappi, president of Alliance Exploration, which operates the North Slope unit adjacent to the Prudhoe Bay unit, was sent a certified letter from the commissioner saying Alliance's request for a reconsideration was denied.

An "appellant affected by this final administrative order and decision" can file an appeal with the Superior Court within 30 days, per "Alaska Rules of Court and to the extent permitted by applicable law," Feige wrote.

In Alliance's plan of exploration, approved by the division in 2017 in conjunction with Guitar unit formation, the company promised to drill a well in the winter of 2018 or 2019.

The well was to penetrate the Ivishak, the formation that hosts the Prudhoe Bay reservoir, with a lateral well targeting a seismic anomaly in the Kuparuk C.

Positive results from the first well would trigger a plan for delineation drilling, Alliance said.

Oil potential indicates a potential upside of 200-300 million barrels of oil, another company executive previously told Petroleum News.

—KAY CASHMAN

● OBITUARY

Oil tycoon T. Boone Pickens dies at 91

PETROLEUM NEWS

T. Boone Pickens Jr., a brash and quotable oil tycoon, died Sept. 11. He was 91.

Pickens suffered a series of strokes in 2017 and was hospitalized that July after what he called a "Texas-sized fall."

An only child who grew up in a small railroad town in Oklahoma, after graduating with a degree in geology Pickens joined Phillips Petroleum, where his father, T. Boone Pickens Sr., was working.

After just three years, he formed Mesa Petroleum, and built a reputation as a maverick, unafraid to compete against oil industry giants.

In the 1980s, Pickens switched from drilling for oil to plumbing for riches on Wall Street. He led bids to take over big oil companies.

"It has become cheaper to look for oil on the floor of the New York Stock Exchange than in the ground," he said.

In 1983, Mesa made a bid for major Gulf Corp. Although it was unsuccessful, Mesa's bid forced Gulf to accept a merger with Chevron. An investment group led by Pickens earned $760 million when the shares it bought in Mesa appreciated during the takeover.

Later in his career, Pickens championed other energy sources, including natural gas and wind power. He snagged politicians to support his "Pickens Plan," which envisioned an armada of wind turbines across the middle of the country that could generate enough power to free up natural gas for use in vehicles.

"I've been an oilman all my life, but this is one emergency we can't drill our way out of," he said.

Pickens couldn't duplicate his oil riches in renewable energy. In 2009, he scrapped plans for a huge Texas wind farm and eventually his renewables business failed.

Mesa predecessor to Pioneer Natural Resources

In 2007, Forbes estimated Pickens' net worth at $3 billion. He eventually slid below $1 billion and off the magazine's list of wealthiest Americans. In 2016, the magazine put his worth at $500 million.

Besides his business interests, Pickens made huge donations to Oklahoma State University — the football stadium bears

see PICKENS page 11

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ANS CRUDE PRICE

Is OPEC in control?

Oil prices are like the weather — everybody talks about them, but, it seems, nobody can do much about them. Forecasting is an art subject to constant revision.

The ability of OPEC and its kingpin nation Saudi Arabia to control prices, has been counteracted in recent years by surging unconventional production in the United States.

The Saudis, however, are looking for higher oil prices — at least $80 per barrel, to fund Crown Prince Mohammed bin Salman's efforts to diversify the economy and create jobs. In addition, higher prices would benefit the upcoming IPO of state oil company Saudi Aramco.

The Saudis may be mounting a more aggressive stance on oil prices, based on recent shakeups.

King Salman replaced the country's powerful energy minister, Khalid al-Falih, with one of his own sons, Prince Abdulaziz bin Salman, recently minister of state for energy affairs.

But who can say what comes next?

Roger Herrera — for many years the favorite oil price guru to Petroleum News — once in a period of oil price uncertainty may have captured the nature of oil markets best.

"It's in the lap of the gods," he said. ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

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XCD ENERGY

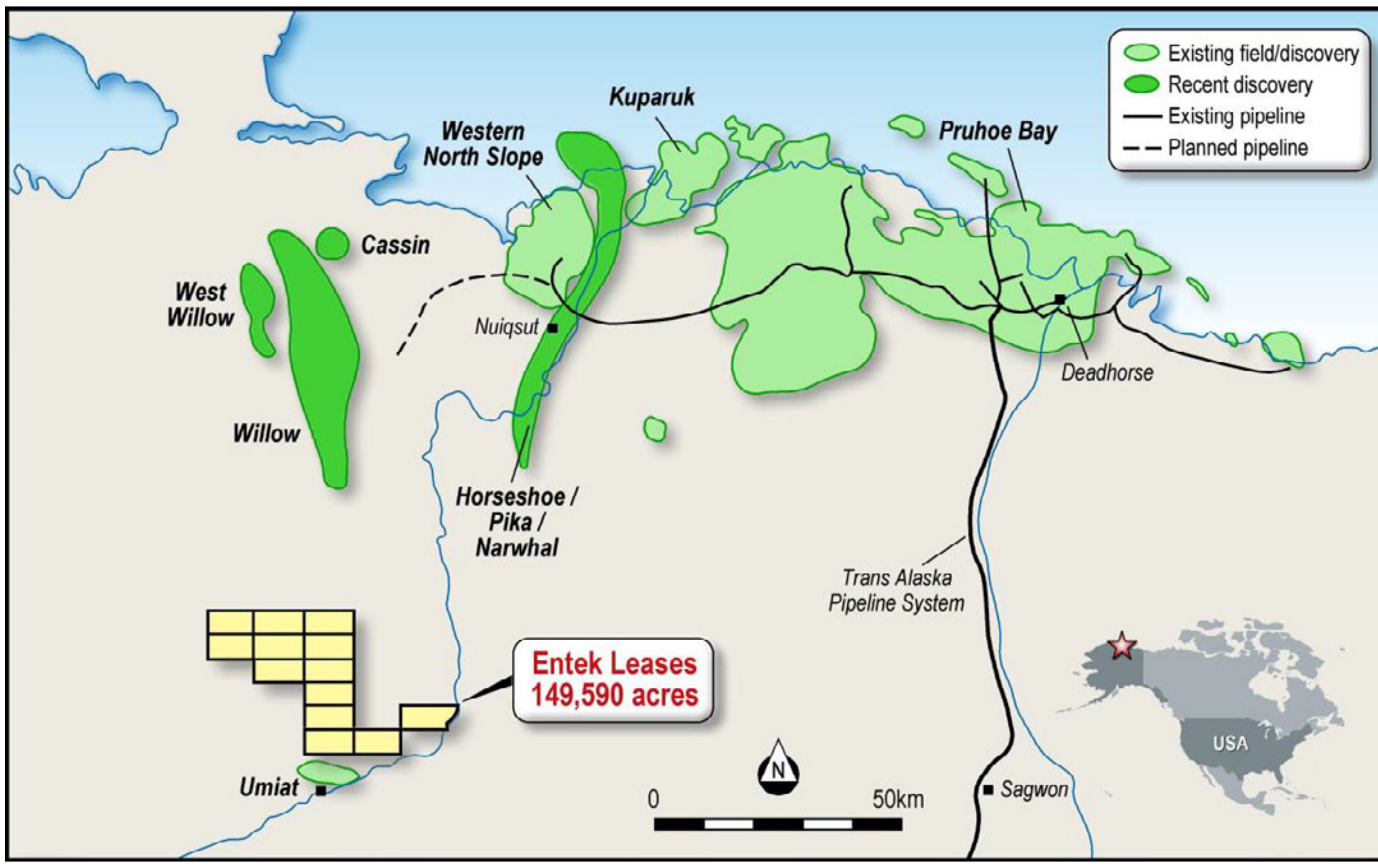
The "chance of discovery for the Merlin lead has been estimated at 13% with a 50% chance of development."

The company says it expects to complete the Integrated Nanushuk Technical Regional Overview, or intro study, at the Peregrine project later in September.

The intro study involves the integration of reprocessed data with other regional seismic and well data to provide an improved understanding of the Nanushuk oil play.

Immediately following completion of the study, an independent prospective resource report covering all the project's leads is due to commence, XCD says.

"We look forward to now completing the intro project and delineating the additional leads already identified and having them independently verified to further add to the overall prospective resources in our acreage in Alaska," XCD managing director Dougal Ferguson was quoted as saying in the Sept. 10 release.



Exploration plans

According to XCD, additional exploration activities to further delineate Merlin and other leads within the Peregrine project could include 3D seismic acquisition.

The company also intends to drill an exploration well in early 2021, "subject to farmout or additional fundraising."

XCD took over the 13 leases making up Peregrine at the start of this year when it acquired Elixir Petroleum subsidiary Emerald House. At the time, XCD was named Entek Energy Ltd, the new name being part of a re-branding as XCD began a new chapter in its history as an active oil explorer in Alaska.

Ferguson was the driving force behind entering Alaska, starting with the acquisition of three leases in NPR-A from veteran Alaska investor and independent Paul Craig.

Elixir and Emerald House, which had some of the same major shareholders as Entek, closed on the sale of those leases and 10 adjoining NPR-A leases in April, giving XCD a total of 14 leases.

Ferguson's take on BP-Hilcorp deal

On Sept. 5, Smallcaps.com.au writer Danica Cullinane interviewed Ferguson to get his reaction to the $5.6 billion acquisition of BP Exploration (Alaska) and its assets by Hilcorp, a privately owned independent.

Ferguson said Hilcorp's acquisition would create "positive flow-on effects" in local industry because it points to "increased activity and additional expenditure on the North Slope."

Hilcorp, he added, would likely be looking at cutting costs and increasing returns by adopting more innovative exploitation techniques.

"He said this is good news for companies such as XCD, which is also trying to find new and different methods than the majors' traditional 'gold-plated' ways," Smallcaps.com.au reported.

"None of this is negative. The fact that BP is selling for $5.6 billion means it's not selling a late life asset. BP has taken the cream and now the new guys will come in, no doubt cut costs and extend the life of these fields with new and innovative thinking," Ferguson told Cullinane.

Ferguson also reportedly told him the Bureau of Land Management's recently issued draft environmental impact statement was good news for XCD, bringing infrastructure closer to its Peregrine project.

"If a discovery is made at Project Peregrine, where we are chasing the same Nanushuk shallow oil play as the Willow field, this new infrastructure shows there is a roadmap to development," Ferguson said.

"It is arctic, and it is a remote area, but as Willow is developed over the next few years, the Conoco operated half billion barrel resource will commence production and that can only be positive for XCD given our proximity to the Willow field," he said.

"This shows that our lease area can be developed economically, and the regulators and local communities are supportive of development in this region," Ferguson added.

—KAY CASHMAN

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INSIDER

Conoco alone owns more than 50% of current Alaska North Slope oil and natural gas liquids production. If it would take over as operator of Prudhoe Bay, the big independent would operate about 85% of all North Slope oil and NGLs, possibly spurring federal and state concerns about one company controlling the region and its facilities.

An (unconfirmed) 2014 agreement between BP, Conoco and Exxon that would allow Conoco to operate half the field and Hilcorp the other half might relieve some worries.

Here is what happened the last time a deal between oil companies threatened to leave the North Slope with one primary oil producer.

In mid-1999, BP Amoco and ARCO (Atlantic Richfield Co.) announced a merger agreement that would have included ARCO Alaska and its assets.

While the state of Alaska reached a comparatively easy settlement, the feds were more difficult to satisfy.

The debate that followed the merger announcement led to the Federal Trade Commission saying in February 2000 that it would seek a preliminary injunction in federal district court to prevent the merger of the two companies. FTC said the deal would, among other things, violate antitrust laws by lessening competition in the exploration and production of Alaska North Slope crude and its sale to West Coast refineries.

If the merger were allowed to proceed, FTC said, BP alone would control 75% of the production of ANS crude oil.

By mid-April 2000, the agency and the companies had settled their differences, the resultant agreement requiring BP to divest all ARCO's assets relating to oil production on Alaska's North Slope to Phillips Petroleum (or another FTC-approved purchaser). With limited exceptions, the divestitures had to take place within 30 days.

—KAY CASHMAN

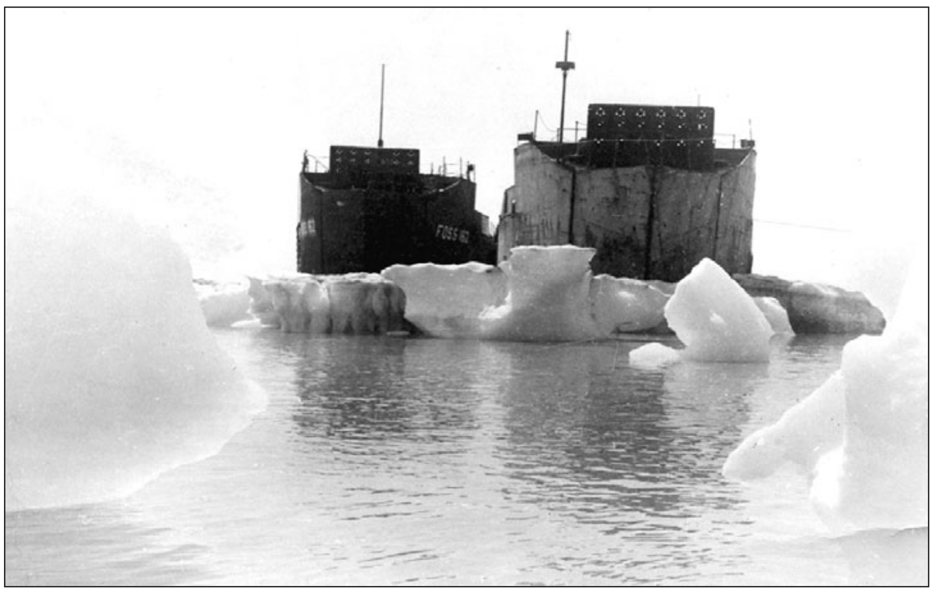
Mull sits on Richfield Katalla well

CONOCOPHILLIPS' PREDECESSOR Richfield Oil drilled two wells in the early 1960s near the abandoned Katalla oil field along the Gulf of Alaska.

The Katalla oil field had been in production from 1902 through 1933, yielding a total of 153,992 barrels of oil from 18 shallow wells that tapped the Poul Creek formation.

COURTESY GIL MULL

Gil Mull



Phillips Petroleum, predecessor to ConocoPhillips, first came to Alaska in 1953 with its partner Kerr-McGee to do surface exploration on their 1 million acres of federal leases in the Katalla-Yakataga region. Their first exploration party used this old LST warship to bring supplies into the area.

Processed at the Katalla oil refinery, the oil was poured into wooden barrels and transported by horse-drawn railway about a mile to the Katalla wharf for shipment to Cordova, where it was used in Copper River Railway locomotives as a lubricant.

Production stopped when the Katalla oil refinery burned down in 1933.

As for company lineage, Richfield merged with Atlantic Refining to become Atlantic Richfield Co. or ARCO, and then its Alaska arm, ARCO Alaska, was sold in 2000 to Phillips Petroleum, which later merged with Conoco to become ConocoPhillips.

Mull was reminded of Richfield's Katalla wells when he read the Aug. 11 story in Petroleum News, "Back to Katalla for oil," which reported on the state's issuance of a preliminary finding on a 65,773-acre Gulf of Alaska exploration license for Cassandra Energy Corp. in the Katalla area.

Nikiski-based Cassandra also has a lease-purchase option on the 465-acre Katalla oil field with the Welch family of Cordova.

Between 1954 and 1963, industry came back to take another look at the region. Twenty-five new wells and core holes were drilled then, none of which discovered any commercial amounts of oil.

At the time, H.C. "Harry" Jamison, a young, mid-career geologist out of California, was administrative assistant to Mason Hill, Richfield's manager of exploration.

In 1960, Jamison made his first trip to Alaska, tasked with doing troubleshooting on the Katalla-Yakutat project for Richfield with partners Sinclair and British Petroleum.

In early 1961, Richfield reorganized its Alaska operation, putting Jamison in charge as exploration supervisor for Alaska and the Pacific Northwest.

"It was Harry Jamison who sent me to Katalla," Mull said.

In 1961, Richfield drilled the Bering River No. 1 well near Bering Lake, with a true vertical depth of 6,175 feet, penetrating the Tokun and Kulthieth formations. And in 1962, the company drilled the Bering River No. 2 well at Bering River; which Mull sat on. Its TVD was 6,019 feet, penetrating the Poul Creek and Tokun formations.

"We got some oil shows in the wells, but nothing else," he said.

"What I remember most when I think of that drilling, which took place in the winter, is lots of rain and always being wet. … It was quite an experience for someone new to Alaska. It was my first well in the state."

Both of Richfield's wells were plugged and abandoned.

—KAY CASHMAN

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PICKENS

his name, and he gave $100 million for endowed faculty positions. His foundation gave millions to other schools and charities.

Pickens lost control of debt-ridden Mesa, and his bullishness on natural gas prices turned out to be a costly mistake. Mesa eventually merged with another energy producer to become Pioneer Natural Resources, once an Alaska operator and now a major player in Texas' Permian Basin.

After leaving Mesa, Pickens started BP Capital Management, a billion-dollar hedge fund focused on energy commodities and equities that delivered mammoth gains.

After his fall in July 2017, he wrote on LinkedIn that he was still mentally strong, but "I clearly am in the fourth quarter." ●

—The Associated Press contributed to this report

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LEGAL FIGHT

consent ... of First Nations and Indigenous peoples before projects like (Trans Mountain) can proceed."

"Under the duty to consult First Nations and Indigenous peoples do not have a right to veto the project," he said.

Stratas said a project "is not to be hamstrung by multiple, unnecessary, long forays through the judicial system."

To that end he said the review process will be expedited — some legal experts estimate it will take no longer than three months — and is not legal ground to stop work on the C$7.4 billion project to almost triple Trans Mountain's capacity to export 890,000 barrels per day of oil sands bitumen to Asia.

Construction underway

Trans Mountain said construction is already underway at the Burnaby tanker terminal in the Port of Vancouver and more is scheduled to begin later in September on the right of way in Alberta.

It expressed confidence that "all certificates and approvals obtained to date (are valid)."

Tim McMillan, chief executive officer of the Canadian Association of Petroleum Producers, said that while his organization is disappointed with the court's decision to grant an appeal, it is just a setback.

TMX has "already undergone a lengthy, thorough and extensive regulatory review process, including extensive consultation with all stakeholders. (The project) has been deemed to be in the best interest of all Canadians," he said.

Government frustration

However, frustration within the Alberta government was aired by Energy Minister Sonya Savage who said the legal process is being reworked "over and over and over again. This is part of the game plan of some of these activist organizations" who repeatedly use litigation "until the project proponents give up."

The Trudeau cabinet has twice approved TMX, which is set to come on stream by mid-2022, but that timeline could be in jeopardy if opponents continue their efforts to sway the courts and possibly take their cases to the Supreme Court of Canada.

Even the federal court was bothered that the Trudeau government — which is now the sole owner of TMX — had presented no legal submissions or evidence to counter First Nations' claims that the consultations with them were inadequate.

Stratas wrote that the government and cabinet might have "strong evidence" to defend the adequacy of their consultations.

"At this time, however, the respondents have withheld their evidence and legal submissions on these points. So the analysis cannot progress further," he said.

Brad Morse, dean of the law faculty at Thompson Rivers University in Kamloops, British Columbia, was sharply critical of the government's failure to participate in the appeal, suggesting that might reflect Trudeau's reluctance to oppose First Nations during a federal election campaign. ●

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ANS CHANGES

BOB DUDLEY

Ford and Haynesville assets from BHP for $10.5 billion in 2018. That value is being offset by this sale and a U.S. Lower 48 divestment program that targets the bulk of BP's assets outside of its three key growth shale plays."

Wood MacKenzie analyst Rowena Gowen said BP is not the only major divesting mature assets.

"The majors are making progress with their divestment campaigns. This will mean long-held assets and territories will be let go. BP made such a deal today with its sale of all U.S. Alaska assets to privately-owned Hilcorp," Gowen said.

BP CEO Bob Dudley said Aug. 27, "We are steadily reshaping BP and today we have other opportunities, both in the U.S. and around the world, that are more closely aligned with our long-term strategy and more competitive for our investment."

Hilcorp CEO Greg Lalicker said that the Alaska acquisition fits into the privately owned independent's strategy: "Hilcorp has a proven track record of bringing new life to mature basins, including Alaska's Cook Inlet and the North Slope."

Myers' thoughts on deal

Weighing in on Hilcorp's agreement to purchase BP Exploration (Alaska) and its assets, Mark Myers, a former commissioner of the Alaska Department of Natural Resources and former director of the U.S. Geological Survey, told Petroleum News Sept. 11, "it's not unusual to see a transition to smaller companies as assets mature. It's part of the evolution of the core infrastructure on the North Slope."

MARK MYERS

An "advantage" with Hilcorp, Myers said, is that "through its operation of the adjacent Milne Point field, it has shown it can introduce new technological approaches and investment that economically increase production."

"Hopefully, Hilcorp will have the opportunity to operate as they did at Milne Point and increase production, especially with the expansion of viscous oil and extension exploration and development," he said.

On the downside, he noted, "an operation the size of Prudhoe will stretch a company the size of Hilcorp and likely will mean fewer jobs on the North Slope and less corporate income tax for the state."

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Petroleum news

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EXPANDED SALE

ing in August 2014.

In the end only one company, Cook Inlet Energy, submitted a final bid, committing to spend $1.5 million over four years for an exploration license on 168,581 acres of state land on and offshore the Iniskin Peninsula. The minimum work commitment for the license was $1 million. There was also a one-time fee of $1 an acre for the license.

When it applied for the license Cook Inlet Energy was a Miller Energy company. That company emerged from bankruptcy proceedings in 2016 as Glacier Oil & Gas and didn't follow through with the exploration license.

Exploration license area

In its 2014 finding the division described the Southwest Cook Inlet exploration license area as some 169,000 acres in and around the Iniskin Peninsula, Iniskin Bay, Oil Bay, Chinitna Bay and adjacent state-owned waters.

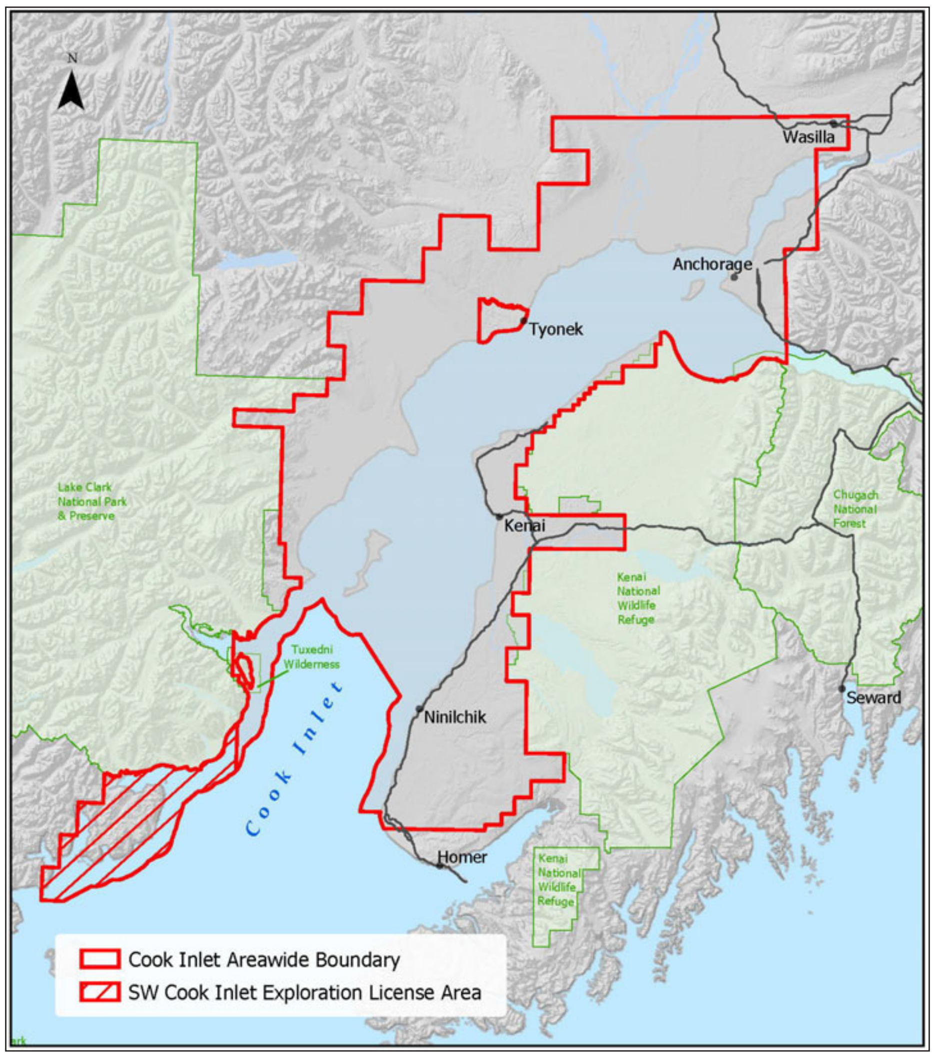
Oil seeps have been known on the Iniskin Peninsula since at least 1853, the division said, and were reportedly first sampled in the 1880s, with oil prospecting claims staked in 1892 and 1896.

Live oil seeps were mapped at Well Creek, 1/2 mile north of the head of Dry Bay near the south end of the peninsula; at Brown Creek 2 miles north of the head of Dry Creek Bay on the southeast side of the peninsula; and Fitz Creek, in the interior of the peninsula.

The division said all the seeps are along mapped faults.

Early drilling

The earliest exploration wells in Cook Inlet were drilled near Oil Bay and the Well Creek oil seeps by the Alaska Petroleum Co., beginning in 1902. The division said there are no known official records on the first well, completed in 1903, but it is reported to have reached a total depth of 305 meters with continuous gas below 58 meters and "considerable" oil flow at 213 meters. As drilling continued, a strong water flow shut off the oil flow, although gas flow continued even after drilling ended.



A second well by the company, drilled a mile northwest of the first in 1903, encountered oil shows while drilling in badly caving shale at a depth of 98 meters, the division said. The well was abandoned at a total depth of 137 meters due to collapsing shale.

A third well, 76 meters south of the previous well, reached 274 meters and encountered oil and gas in three thin sandstones at some 236 meters as well as gas shows at various depths, some sufficient to blow the water out of the hole to a height of 6 meters. There is no information available on the fourth well Alaska Petroleum Co. drilled.

Alaska Oil Co. drilled a well in 1902 near the seep on Brown Creek north of Dry Bay. The well was abandoned, with no oil shows, at just 98 meters when drilling tools were lost in the hole, the division said. A second attempt nearby in 1903 was abandoned at a shallow depth.

"Subsurface exploration shut down in 1903, and no additional wells have been drilled at either Oil Bay or Dry Bay since this initial prospecting phase."

1930s drilling

Only geologic field studies took place in the area between 1903 and 1934, with U.S. Geological Survey geologists describing the potential structural trap now known as the Fitz Creek anticline.

The Iniskin Bay Association obtained exploration rights near the Fitz Creek oil seep, built a road from Chinitna Bay and began drilling the Iniskin Bay Association No. 1 well in late 1936, the division said, work which continued over four summers and was suspended in 1939 at a total depth of 2.7 kilometers after penetrating Middle Jurassic sedimentary rocks. The well encountered trace oil and gas shows at 1.5 kilometers upon penetrating the Fitz Creek fault zone and penetrated high pressure gas between 1.5 and 2 kilometers and a thin oil bearing sandstone at 2.1 kilometers. Twelve barrels of high gravity oil were recovered.

"When the well was abandoned in 1939, it was flowing 240 barrels of water per day with minor oil and gas," the division said.

Post World War II

Exploration in the license area halted during World War II and resumed when a new group of investors, the Iniskin Unit Operators, formed in 1953, drilling the Beal No. 1 between 1954 and 1955 213 meters east of the Fitz Creek fault. Gas shows were noted between 748 and 788 meters and at 1.15 kilometers, with core samples taken just below 1.95 kilometers yielding oil shows. There were further oil shows below 2.35 kilometers and the well yielded 14 barrels of oil rich fluid at 2.38 kilometers, the division said. The operator reentered Beal No. 1 in 1956 and 1957, perforating selected intervals, and obtained a small quantity of oil and gas.

The lease was transferred to Alaska Consolidated Oil Co. in 1958, "but further efforts to achieve commercial flow rates, including hydraulic fracture stimulation, were unsuccessful," the division said.

That company drilled one additional well, the Antonio Zappa No. 1, in 1958-59 some 732 meters west of the Beal No. 1. That well bottomed at 3.42 kilometers total measured depth and encountered numerous minor to fair oil shows beginning at some 213 meters and become abundant below 1.83 kilometers.

The division said the most recent exploration work in the area was a 41 mile 2D seismic shoot done by SAExploration for Hilcorp Alaska between Chinitna Bay and Iniskin Bay in the summer of 2013. ●

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ANS CHANGES

One other issue Myers raised is "what the state will need in bonding, and what guarantees Hilcorp can give the state. The state will have to carefully review Hilcorp's balance sheet and not fully release BP from its obligations for long term field asset abandonment, removal and restoration." (The deal between Hilcorp and BP is subject to state and federal regulatory approval, so the state will have an opportunity to address these and other possible issues.)

"One other question that should be looked at is," Myers said, "how is facility sharing going to work on the North Slope with BP gone? Will facility infrastructure sharing agreements change?"

Billions of barrels left at Prudhoe

How much oil is left in the Prudhoe Bay field for a new operator to pursue?

According to a recent Wood Mackenzie report, the remaining Prudhoe reserves include more than 13 billion barrels of oil and condensate, 1 billion barrels of natural gas liquids, and an expected 23 trillion cubic feet of natural gas.

When Prudhoe Bay went into production in 1977, the initial estimated ultimate recovery was 9.6 billion barrels of oil. To date, however, it has generated more than 13 billion barrels of oil. According to BP, a bit more than 1 billion barrels of producible oil remain in the field, excluding most of the Put River formation liquids.

At first, field reservoir pressure was high and there was a 600-foot oil column but production over the years has lowered the pressure, Fabian Wirnkar, BP vice president for reservoir development, said in an October 2018 presentation.

Waterflood and gas injection have been used to sustain reservoir pressure to levels where oil production can continue.

BP recycles and reinjects about 8 billion cubic feet of gas per day through the Prudhoe reservoir, without which the field would no longer produce any oil, Wirnkar said.

Put River formation recovery

In addition to infield exploration for untapped pockets of oil using 3D seismic, BP has been looking to capitalize on known but difficult to produce reserves in Prudhoe's initial participating area, or IPA, by developing creative production techniques based on data analysis and advanced technology.

The company obtained Alaska Oil and Gas Conservation Commission approval in late 2018 to allow for commingled downhole production for wells completed in both the Prudhoe oil pool and the Put River oil pool which overlies the main reservoir. The ruling allowed production of some 6.9 million barrels of oil in place in the IPA's Put River formation, which would otherwise be stranded.

Put River consists of three lobes — Central, Southern and Western — with a fourth lobe, the Northern, in hydraulic communication with the Prudhoe oil pool. The Southern lobe of Put River has had production since 1999 with an active waterflood.

The Central lobe contains an estimated 1.1 million to 2.7 million barrels of oil in place and the Western lobe about 69.6 billion to 104.4 billion cubic feet in place with a condensate yield of approximately 40 barrels per million cubic feet, and a condensate in place value of between 2.8 million and 4.2 million barrels of oil.

AOGCC said several wells penetrating the Prudhoe and Put River oil pools would be candidates for downhole commingling, which "should allow for increased flowrates and flow velocity in the tubing and reduce the potential for the hydrate deposition that is problematic in production from wells completed solely in the (Put River pool). Since standalone production of the Central and Western lobes is not viable due to hydrate deposition those reserves are essentially trapped. Commingling … will allow these resources to be recovered."

Myers: North Slope not mature

Myers, a geologist, has been saying for years that a lot of oil was missed or ignored on the North Slope in the first waves of exploration. The oil province, he said Sept. 11, should no longer be viewed a mature basin.

"The size of the Nanushuk discoveries is another demonstration that the North Slope shouldn't be classified as a mature basin. The new oil resources that are under development will lead to a significant increase in North Slope production," he said, referring to new Nanushuk developments by Oil Search and ConocoPhillips.

There are other parts of the Slope that have potential for similar large-scale stratigraphic traps to that of the giant Nanushuk discoveries west of the central North Slope, Myers said, noting that USGS and other assessments indicate "a very significant remaining undiscovered oil and gas endowment."

—KAY CASHMAN

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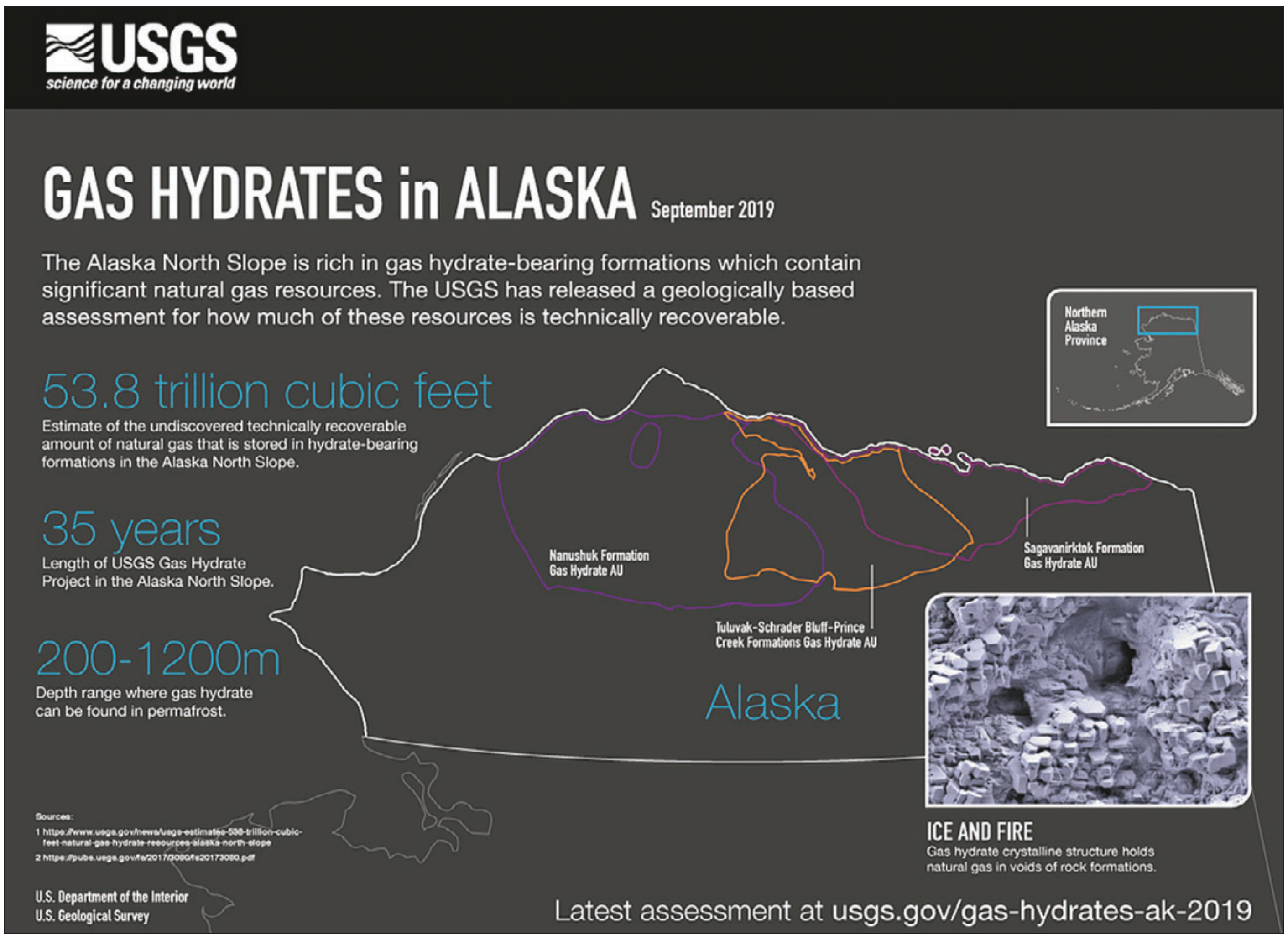

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GAS HYDRATES

line. The area covers 41,089 square miles and encompasses federal, state, and Native lands

Access to 3D seismic mapping, along with a greater understanding of gas hydrate reservoir properties, yielded estimates that were more precise, the federal agency reported.

The assessment methodology assumes that the resource can be produced by existing conventional technology. To date, USGS says, there is no known commercial production of natural gas from gas hydrates and the commercial viability of hydrate reservoirs is not yet known.

That assumption is based on both limited field testing and numerical production models of gas hydrate-bearing reservoirs. No analysis was provided in the report as to whether it would be profitable to produce the resources.

The assessment methodology assumes that the resource can be produced by existing conventional technology. To date, USGS says, there is no known commercial production of natural gas from gas hydrates and the commercial viability of hydrate reservoirs is not yet known.

There have been two methane hydrate wells drilled on the North Slope, with the Eileen gas hydrate trend being the primary target of both: One, the 2007 Mount Elbert stratigraphic test well enabled the gathering of gas hydrate cores and evaluated the production characteristics of the hydrates that the well penetrated; the second, the Ignik Sikumi well, drilled in 2011-12, tested short term gas production using a couple of production techniques.

The next phase of the project will include drilling at least one more well in the winter of 2021-22, followed by a production testing program in 2021 or 2022.

The permafrost associated hydrates under the North Slope, while extensive, exist in a series of discrete sand reservoirs at various depths and locations and are bounded by faults and downdip water contacts. A production well would obviously need to be located where it can penetrate one or more of these reservoirs.

Group effort

In March, the Department of Energy's National Energy Technology Laboratory published information on the Ignik Sikumi well. The drilling of the well was part of a project aimed at testing the production of natural gas from hydrate as a potential future commercial gas resource.

NETL had formed a partnership with Japan Oil, Gas and Metals National Corp., USGS and Petrotechnical Resources of Alaska, or PRA, for the drilling of the well. BP, operator of the Prudhoe Bay unit, oversaw the drilling.

The NETL presentation says that the methane hydrate research team had considered a test site on unleased land on the North Slope but had discounted that possibility because of high logistics costs, the lack of support infrastructure, an uncertain regulatory environment and relatively high geologic risk. Instead, the team, in cooperation with the Prudhoe Bay working interest owners, opted for a location on the Slope's gravel road system in the western part of the unit. The location is clearly understood from a geologic perspective, has multiple hydrate reservoir zones and would minimize any

see **GAS HYDRATES** *page 15*

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GAS HYDRATES

interference with operations in the unit.

The location will enable production testing for at least six months, and optimally 18 to 24 months.

The testing will focus on gas production through depressurization of the hydrates, a technique that testing in the Ignik Sikumi well indicated to be particularly favorable. However, the emphasis will be on the science of hydrate production rather than demonstrating production rates. And thermal, mechanical and chemical well stimulation technologies will be available, as necessary. The intent is to use proven oilfield technology where possible, NETL says.

Best available science

USGS is "committed to providing the most up-to-date, publicly available, peer-reviewed estimates of the nation's energy resources," Walter Guidroz, program coordinator for the USGS energy resources program, was quoted as saying in the Sept. 10 release. "As more information becomes available, we sometimes need to revise our assessments to ensure they reflect the best available science."

The report updates a 2018 USGS assessment that estimated about 85 trillion cubic feet of undiscovered, technically recoverable gas resources within the gas hydrates of the North Slope. It is this refined analysis that yielded a smaller gas volume estimate in the 2018 assessment when compared to the 2008 assessment, USGS says.

Gas hydrates are naturally occurring, ice-like solids in which water molecules trap gas molecules in a cage-like structure. They are only stable within a narrow range of temperatures and pressures and are usually found in seafloor sediments and in Arctic onshore permafrost environments.

Although many gases form hydrates in nature, methane hydrate is by far the most common, and there are thought to be significant natural gas resources contained in the world's gas hydrate accumulations.

In addition to the North Slope research, USGS says it has been participating in and sometimes managing large-scale drilling projects that investigate the resource potential of gas hydrate throughout the United States, as well as in offshore India and the Gulf of Mexico.

The USGS gas hydrate project conducts multidisciplinary field studies, participates in national and international deep drilling expeditions, and maintains a laboratory program focused on hydrate-bearing sediments, the agency says.

"The study of gas hydrate as an energy resource is still an emerging field," USGS scientist Tim Collett, lead author of the assessment, says. The agency has been conducting research on gas hydrates since the 1980s. "Every time we conduct these assessments, we incorporate more and higher quality data, and our estimates become more precise."

Nanushuk, Tuluvak-Schrader Bluff-Prince Creek, and Sagavanirktok

According to its Sept. 10 release, USGS oil and gas assessment methodology begins with the volume of rock to be assessed in the total petroleum system, or TPS, being apportioned into subunits called assessment units, or AUs. The assessment procedure generally estimates the number and size of undiscovered hydrocarbon accumulations and assesses the geologic risk associated with each AU. The northern Alaska gas hydrate TPS includes Cretaceous and Tertiary reservoir rocks divided into three AUs, listed from oldest to youngest: the Nanushuk formation, the Tuluvak-Schrader Bluff-Prince Creek formations, and the Sagavanirktok formation.

> *"These estimates are associated with large ranges of uncertainty, which reflect the immature stage of exploration for this potential resource and concerns associated with producibility of gas hydrates … the total undiscovered gas resources at the F95 probability for each AU could be zero."*
> *—U.S. Geological Survey*

Only gas hydrates below the permafrost section were assessed, thus limiting the AUs to the stratigraphic interval below the base of the permafrost and above the base of the gas hydrate stability zone. Free gas potentially trapped below the gas hydrate stability zone was not assessed.

Two critical parts of the USGS assessment procedure are the accurate predictions of the expected size and number of undiscovered hydrocarbon accumulations within each of the delineated AUs. This assessment "relied heavily" on the analysis of 3D seismic data acquired by industry, which were used to characterize the size, number, and distribution of gas hydrate accumulations in each of the three AUs, USGS says.

The minimum accumulation size considered was 30 billion cubic feet of technically recoverable gas. USGS scientists used established gas hydrate seismic attribute analysis techniques to identify 103 seismically inferred gas hydrate accumulations throughout the northern Alaska gas hydrate TPS. These seismically inferred gas hydrate accumulations were used in the latest assessment to estimate the size and number of gas hydrate accumulations in each AU.

Geochemical analyses of drill cuttings and core samples from wells drilled in state lands between the Canning and Colville rivers and within NPR-A indicate that the gas within the drilled and well log inferred gas hydrate accumulations is in part from thermogenic sources, with the thermogenic gas migrating from deeper sources, including known conventional oil and gas accumulations.

Thermal conditions conducive to the formation of permafrost and gas hydrates are believed to have persisted in the Arctic since the end of the Pliocene — about 2.58 million years ago

In addition, most permafrost associated gas hydrate accumulations probably developed from preexisting free gas fields that originally formed in conventional hydrocarbon traps and were later converted to gas hydrates upon the onset of glaciation and cold Arctic conditions, the Sept. 10 assessment says.

Large range of uncertainty

In its assessment summary, USGS said the estimated mean total for the three North Slope gas hydrate AUs is 53.8 trillion cubic feet of gas recoverable.

"These estimates are associated with large ranges of uncertainty, which reflect the immature stage of exploration for this potential resource and concerns associated with producibility of gas hydrates," the agency says.

"Because of the remaining uncertainty associated with the producibility of gas hydrates, each AU probability was risked at a factor of 0.9, which resulted in the estimate that the total undiscovered gas resources at the F95 probability for each AU could be zero," USGS says.

The agency's Alaska assessment team includes Collett, Kristen A. Lewis, Margarita V. Zyrianova, Seth S. Haines, Christopher J. Schenk, Tracey J. Mercier, Michael E. Brownfield, Stephanie B. Gaswirth, Kristen R. Marra, Heidi M. Leathers-Miller, Janet K. Pitman, Marilyn E. Tennyson, Cheryl A. Woodall and David W. Houseknecht. ●

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