Petroleum news

Vol. 26, No. 46 • www.PetroleumNews.com

A weekly oil & gas newspaper based in Anchorage, Alaska

Week of November 14, 2021 • $2.50

page 3 EIA: low inventory, weather worries, high LNG exports drive Henry Hub

Santos likes Pikka; Oil Search list of oil-rich AK finds grows

BREAKING NEWS

Probably the most important news released by Oil Search Ltd. on Nov. 11 was confirmation that Oil Search Alaska has identified two major new trends (Quokka and Horseshoe/Stirrup) with similar scope and scale to Pikka (see map in pdf and print versions of this story).

But the news that was making headlines outside Alaska on Nov. 11 was that Oil Search Ltd.'s acting CEO Peter Fredricson told Dow Jones Newswires that Santos Ltd. likes the proposed Pikka oil development in Alaska, as opposed to much earlier indications that Santos was interested in selling a chunk of the project and letting the buyer (ConocoPhillips was inferred) operate the project.

see **OIL SEARCH UPDATE** page 14

EIA: Volatility continues; demand overtakes supply; jet fuel uptake

Alaska North Slope crude plunged $2.63 Nov. 10 to close at $83.77 per barrel, while West Texas Intermediate slid $2.81 to close at $81.34, and Brent dropped $2.14 to close at $82.64.

The slide ended three days of gains for the indexes, after three days of losses carried WTI to a close of $78.81 on Nov. 4, while ANS and Brent held above $80 at $81.93 and $80.53, respectively.

Prices recovered in early trading Nov. 11, taking WTI above $82, but fell later. As Petroleum News went to press, WTI was down 61 cents to $80.73.

Bearish factors seized the oil markets Nov. 10, including a sharp rise in the U.S. Dollar and the threat of additional supply

see **OIL PRICES** page 15

AEA evaluating Bradley Lake expansion with Dixon Glacier melt

CURTIS THAYER

Following the completion of the Battle Creek diversion project in 2020, the Alaska Energy Authority is eyeing a further possible way to increase the power output from the Bradley Lake hydroelectric facility in the southern Kenai Peninsula. Apparently the Dixon Glacier, about five miles southwest of Bradley Lake, is receding: Increased water flow from the melting glacier could potentially be used to generate electricity. Currently AEA is investigating the feasibility of this hydropower expansion, Curtis Thayer, AEA executive

see **BRADLEY LAKE** page 13

Alternative energy setbacks

As Alberta's fossil-fuel based energy sector steps up its drive for alternative, sustainable sources it has been hitting some bumps in the road.

Topping the list of woes was a plan by AltaGas to create salt caverns north of Halifax, Nova Scotia, which the company now says is no longer part of its business focus.

The decision came 13 years after construction started on the ill-fated project, which will now be decommissioned because of the shift in AltaGas priorities following its sale of a stake in a Halifax-based gas utility that would have been the main customer for the caverns.

"The project has received mixed support, challenges (from Indigenous groups and their allies) and construction delays," AltaGas said.

see **ALTERNATIVE SETBACKS** page 12

LAND & LEASING

AEX sells Placer

Buyer's name not public; deal signed March 29; Pikka, Mitquq, not Mustang?

By KAY CASHMAN

Petroleum News

CHAIT BORADE

On March 29, ASRC Exploration sold its Placer unit leases on Alaska's North Slope. No public announcement was made.

Although AEX does not name the buyer of the leases in the public portions of its filings with Alaska's Division of Oil and Gas, its jargon does suggest two interested parties: 1. Oil Search (or, just as likely, a company interested in buying into the Pikka unit and nearby acreage), and 2. the buyer of the Mustang assets in the Southern Miluveach unit, which is up for sale and rumored to have a deal pending.

Here is what is known — i.e. in the public record.

A little over a year ago, AEX, operator of the small North Slope Placer unit, told the division in its fifth proposed Placer plan of development, or POD, it was continuing development and facility sharing discussions for Mustang with the Alaska Industrial Development and Export Authority.

AEX also reiterated that it was looking at sending its oil to either the Mustang pad in the Southern Miluveach unit or to the new Pikka development. (see Pikka area map on page 14 of this issue).

see **PLACER SALE** page 12

FINANCE & ECONOMY

Billions of barrels

GBP updip appraisal well expected to sweeten EURs for NS Theta West play

By STEVE SUTHERLIN

Petroleum News

Great Bear Pantheon is talking billions of barrels.

Its Theta West 1 well — to be drilled on the North Slope this winter season — is incredibly significant for the Pantheon Resources PLC subsidiary, and for Alaska if the company's expectations for the well are met.

The Theta West ice pad will be 10 miles west of the Talitha pad where GBP's Talitha A exploration well struck light oil last winter.

"We think we are a big part of the future," Pantheon Resources CEO Jay Cheatham told Petroleum News in a Nov. 5 interview.

GBP also plans to reenter the Talitha well this winter to resume testing of zones it ran out of time for as the winter exploration season ended in the spring of 2021, he said.

The company expects to see the same zones and more in the Theta West well, and the expected recoverable resource amounts are gargantuan for the $770 million market cap Pantheon.

"At least a billion" barrels, Bob Rosenthal, Pantheon technical director said. "We think we've got one of the largest discoveries made in the world in the last year."

GBP considers Theta West 1 to be an appraisal well of last winter's discovery at Talitha, he said.

see **THETA WEST** page 9

GOVERNMENT

Playing climate leader

Trudeau pledges C$1B at Glascow, while capping O&G GHG emissions by 2050

By GARY PARK

For Petroleum News

JUSTIN TRUDEAU

Canada's Prime Minister Justin Trudeau strutted the global stage during his three days at the United Nations COP26 conference in Glasgow, Scotland, pulling off the seemingly impossible and reinforcing a growing view that he is intent on dismantling Western Canada's energy industry.

He managed to contort himself in front of delegates at the global summit by promising Canada would contribute C$1 billion to a multibillion-dollar fund to help poorer countries battle climate change, while patting himself on the back for what he views as Canada's leading role in curbing greenhouse gas emissions.

At the same time he poked Alberta in the eye for its failure to attend the gathering and what he views as its dismal performance in the climate war.

For many Canadians his most annoying tactic was to put a fresh shine on what was a key pledge in the governing Liberal party's election campaign two months ago.

He offered no details and no timetable for imposing a limit on emissions produced by Canada's oil and gas sector, perhaps a tacit

see **TRUDEAU IN GLASCOW** page 11

● GOVERNMENT

AOGA onboard with some regulation changes

By KRISTEN NELSON

Petroleum News

The Alaska Oil and Gas Conservation Commission has proposed changes in its regulations and those proposed changes are out for public comment. The changes, public noticed in late September (see story in Oct. 3 issue of Petroleum New), were the subject of a Nov. 3 hearing.

The only comments AOGCC received in advance of the hearing, and the only commenter at the hearing, was the Alaska Oil and Gas Association, represented by its regulatory and legal affairs manager, Dawn Crater.

AOGA's written comments, dated Nov. 2, represented a range of views on the different proposed changes.

Crater said at the hearing that those comments ranged from no comment, comments for the record, recommendations for changes and, for some of the proposed changes, a recommendation that a working group be formed to further work through the changes.

AOGA said it had no comments on the regulatory changes that would make wells drilled from mobile offshore drilling units ineligible for suspension status.

Recommendations

On other proposed changes AOGA said it found the proposed changes unclear and proposed different wording.

One of those changes, AOGA said in its comments, if applied to offshore wells, would potentially require abandonment of suspended wells on platforms, and said an operator could not comply "because the well spacing on the offshore locations is constricted and the removal of the wellhead equipment and casing to the required depth could not be completed until the removal of the existing offshore pad itself." AOGA recommended inclusion of the words "except offshore locations" to resolve this issue.

AOGCC is proposing increasing the frequency of suspended well inspections, which AOGA said "will increase operator administrative and cost burdens to comply," noting costs to access remote well locations with inspection equipment.

The proposed changes also codify what AOGA called "the longstanding practice wherein operator provide transportation to remote locations when an AOGCC inspector could not access the site by commercial transportation services or AOGCC."

AOGA said it has no issue with the idea, but recommends a working group to address a number of issues, including a requirement that AOGCC inspectors follow safety requirements applying to the locations they visit; an expectation that operators provide the same type of transportation for inspectors as provided for employees and other workers; a requirement that the AOGCC inspectors be responsible "for clearing any ethics procedures related to receiving transportation without undue burden on the operator providing transportation"; and reasonable advance notice to the operator when transportation is required and cooperation "on scheduling, arranging safety escorts, and other administrative matters related to travel to and in the oil fields."

At the end of the hearing AOGCC Chair Jeremy Price said the commission would have some follow-up questions and would keep the record open for two weeks, for comments through the close of business Nov. 19. ●

Contact Kristen Nelson at knelson@petroleumnews.com

contents

Petroleum News | *Alaska's source for oil and gas news*

● FINANCE & ECONOMY

EIA: Brent averages $84 in October, up $9

Energy Information Administration says low inventory, weather worries, high level of LNG exports drivers in Henry Hub spot prices

By KRISTEN NELSON

Petroleum News

U.S. natural gas storage levels are rising, the U.S. Energy Information Administration said Nov. 9 in its Short-Term Energy Outlook, but winter weather concerns are contributing to volatile natural gas prices, along with high levels of liquefied natural gas exports.

"Mild weather has limited natural gas consumption and helped bring our storage levels closer to average in recent weeks, but cold winter weather could continue to put upward pressure on prices," EIA Acting Administrator Steve Nalley said in a release accompanying the outlook. "Winter temperatures will be the key driver of natural gas demand, inventories, and ultimately prices," he said.

STEVE NALLEY

EIA said the U.S. electric sector continues to use significant amounts of natural gas, while U.S. LNG exports averaged 9.8 billion cubic feet per day in October, 37% above the October 2020 level.

"U.S. natural gas exports will most likely remain close to capacity for the remainder of this year and in 2022 to meet global demand," the agency said.

The $84 per barrel average for Brent crude oil spot prices in October is a $9 per barrel increase from September and EIA said it expects Brent to average $82 per barrel in the fourth quarter and $72 per barrel next year. The October average is up $43 per barrel from October 2020.

The agency said crude oil prices have risen steadily due to draws on global inventories, averaging as much as 1.9 million barrels per day in the first three quarters of the year. The decision of OPEC+ to keep current production targets unchanged has also impacted prices.

EIA said it expects Brent to average $82 per barrel in the fourth quarter and $72 per barrel in 2022, with growth in production from OPEC+, U.S. tight oil and other non-OPEC countries expected to "outpace slowing growth in global oil consumption."

The agency estimates world crude oil consumption has exceeded crude oil production since the third quarter of 2020. It forecasts global oil demand to exceed global supply through the end of 2021, contributing to some additional stock draws and keeping the Brent price above $80 through December.

"However, we forecast that global oil stocks will begin building in 2022, driven by rising production from OPEC+ and the United States, along with slowing growth in global demand," putting downward pressure on Brent, explaining the $72 average forecast for 2022.

Consumption

EIA estimates that 98.9 million bpd of petroleum and liquid fuels was consumed globally in October, up 4.5 million bpd from October 2020 but down 1.9 million bpd from October 2019.

"We revised our forecast for consumption of petroleum and liquid fuels for the fourth quarter of 2021, partially as a result of fuel switching from natural gas to petroleum in the electric power sector in parts of Asia and Europe," the agency said, a result of increases in natural gas prices in those areas.

Global petroleum and liquid fuels consumption are forecast to average 97.5 million bpd for all of 2021, up 5.1 million bpd from 2020, and forecast to increase by 3.3 million bpd in 2022.

US production

EIA said U.S. crude oil production is estimated at an average of 11.4 million bpd in October, up from 10.7 million bpd in September "as a result of production increases following disruptions from Hurricane Ida."

The agency is forecasting U.S. production to rise to 11.6 million bpd in December, and to average 11.1 million bpd for 2021, increasing to 11.9 million bpd in 2022 "as tight oil production rises in the United States," largely a result of increases in rig counts by onshore operators, expected to offset decline.

US natural gas

The Henry Hub spot price for natural gas averaged $5.51 per million British thermal units in October, up from $5.16 in September and up from an average of $3.25 in the first half of the year. EIA said rising prices reflect inventory levels below the five-year, 2016-20, average, with high demand for natural gas for electric power generation remaining relatively high along with strong global demand for U.S. LNG.

"We forecast that U.S. inventory draws will be similar to the five-year average this winter, and we expect that factor, along with rising U.S. natural gas exports and relatively flat production through March, will keep U.S. natural gas prices near recent levels before downward price pressures emerge."

Uncertainly over seasonal demand is expected to keep natural gas prices volatile, "with winter temperatures to be a key driver of demand and prices."

EIA estimates that U.S. LNG exports averaged 9.8 billion cubic feet per day in October, up 0.3 bcf from September, supported by large price differences between U.S. Henry Hub prices and spot prices in Europe and Asia.

An average export level of 9.8 bcf per day is expected for the year, up 50% from 2020, with LNG exports expected to increase this winter, averaging 11 bcf per day from October through March, and with high levels expected to continue through 2022, averaging 11.5 bcf per day for the year, up 17% from 2021.

see **EIA OUTLOOK** *page 4*

FACILITIES

AIDEA approves West Susitna funding

During its Oct. 27 meeting the board of the Alaska Industrial Development and Export Authority approved the receipt of $8.5 million in state funding to carry out the third phase of a feasibility study for the West Susitna Access Road Project. The concept is to build a road to access natural resources on the west side of the huge Susitna Valley in Southcentral Alaska. The state Legislature had approved the funding as part of the state budget for the current fiscal year.

In addition to the possibility of developing oil and gas resources in the targeted region, the region to the west of the Susitna River has significant mineral resources and forestry. There is also potential for geothermal and hydroelectric energy, as well as agriculture and recreational use.

"Access is a common barrier to developing Alaska's resources," said AIDEA board Chair Dana Pruhs. "With this funding from the legislature to advance predevelopment work, AIDEA can help facilitate access for the Mat-Su Borough to develop purpose-built infrastructure."

Transportation infrastructure support

Gov. Mike Dunleavy stressed the importance of government support for transportation infrastructure that can lead to economic development.

"This important project makes it possible to travel by road from the Point MacKenzie/Big Lake area to the millions of acres on the west side of the Susitna River, opening access to strategic minerals and known proven oil and gas reserves," Dunleavy said.

The anticipated route of the 100-mile road would run west from Big Lake, heading northwest after crossing the Susitna River before terminating not far south of Rainy Pass in the Alaska Range. AIDEA has been working with the Matanuska-Susitna Borough and private partners on the project. Phase one of the project, completed in the fall of 2019, involved the reconnaissance of potential road routes, to view the terrain and assess route feasibility. Phase two, conducted in 2020, assessed potential costs and involved field work that could underpin future Clean Water Act permit applications.

Phase three work

Phase three will involve the procurement of a third-party contractor to assist AIDEA with the U.S. Army Corps of Engineers permit application process, potentially involving some field studies in 2022, Colleen Bryan, AIDEA communications director has told Petroleum News. Work anticipated in preparing an application includes engineering refinement and data gap analysis, together with baseline studies of fish, wetlands and hydrology. Studies of historical and cultural resources in the impacted area will also be required. AIDEA will also need contractor support for the environmental impact statement phase of the project, with a separate independent contractor initiating the environmental impact analysis on behalf of the USACE, Bryan said.

—ALAN BAILEY

● EXPLORATION & PRODUCTION

Baker Hughes US rig count up by 6 to 550

By KRISTEN NELSON
Petroleum News

For the week ending Nov. 5, the Baker Hughes U.S. rotary drilling rig count was up by six rigs from the preceding week to 550, an increase of 250 from 300 a year ago.

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

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

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

The Nov. 5 count includes 450 rigs targeting oil, up six from the previous week and up 224 from 225 a year ago, with 100 rigs targeting gas, unchanged from the previous week and up 29 from 71 a year ago, and no miscellaneous rigs, unchanged from one the previous week and down by three from a year ago.

Thirty-three of the rigs reported Nov. 5 were drilling directional wells, 492 were drilling horizontal wells and 33 were drilling vertical wells.

Alaska rig count unchanged

Texas (254) was up four rigs from the previous week.

Louisiana (48), Oklahoma (44) and Pennsylvania (18) were each up by a single rig.

New Mexico (86) was down one rig.

Rig counts in all other states were unchanged week over week: Alaska (6), California (10), Colorado (12), North Dakota (23), Ohio (10), Utah (9), West Virginia (11) and Wyoming (15).

Baker Hughes shows Alaska with six rigs active Nov. 5, unchanged from the previous week and up by three from a year ago, when the state's rig count stood at three.

The rig count in the Permian, the most active basin in the country, was up by three from the previous week at 271 and up by 124 from a count of 147 a year ago.

International count up 13

Baker Huges issues its international rig count monthly, information it began providing in 1975. The company said international rigs exclude North America; those rigs are included in worldwide figures.

The international count for October, issued Nov. 5, is up by 13 from September to 800, Baker Hughes said, with land rigs up by 21 to 621 and offshore rigs down by eight to 179.

The international count is up by 144 rigs from the comparable count in 2020, 656, with land rigs up by 119 and offshore rigs up by 25.

The Middle East accounts for the most rigs in the international count, 275 in

see **RIG COUNT** page 5

Petroleum news
www.PetroleumNews.com

Kay Cashman	PUBLISHER & FOUNDER	
Mary Mack	CEO & GENERAL MANAGER	
Kristen Nelson	EDITOR-IN-CHIEF	
Susan Crane	ADVERTISING DIRECTOR	
Heather Yates	BOOKKEEPER	
Marti Reeve	SPECIAL PUBLICATIONS DIRECTOR	
Steven Merritt	PRODUCTION DIRECTOR	
Alan Bailey	CONTRIBUTING WRITER	
Eric Lidji	CONTRIBUTING WRITER	
Gary Park	CONTRIBUTING WRITER (CANADA)	
Steve Sutherlin	CONTRIBUTING WRITER	
Judy Patrick Photography	CONTRACT PHOTOGRAPHER	
Forrest Crane	CONTRACT PHOTOGRAPHER	
Renee Garbutt	CIRCULATION MANAGER	

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 26, No. 46 • Week of November 14, 2021
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $118.00 1 year, $216.00 2 years
Canada — $206.00 1 year, $375.00 2 years
Overseas (sent air mail) — $240.00 1 year, $436.00 2 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

continued from page 3

EIA OUTLOOK

"The forecast reflects our assessment that global natural gas demand remains high and several new natural liquefaction trains — the sixth train at Sabine Pass LNG and the first trans at the new LNG export facility, Calcasieu Pass LNG — enter service," EIA said.

EIA estimates dry natural gas production in the U.S. averaged 94.9 bcf per day in October, up from 94.5 bcf in September, and 91.9 bcf in the first half of the year. It is forecast to rise to an average of 95.2 bcf per day for the remainder of the winter, November through March, and to average 96.7 bcf per day in 2022, "driven by natural gas and crude oil prices, which we expect to remain at levels that will support enough drilling to sustain production growth," the agency said.

The international LNG picture

International LNG prices reached $35 per million Btu in northern Asia in the first week of October, and nearly $40 in Europe.

"Prices in Asia were up nearly twentyfold — and prices in Europe up nearly thirtyfold — from record lows during the summer of 2020, when economic responses to the COVID-19 pandemic significantly reduced global energy factors."

Contributing to the increased global spot price were large increases in demand in Asia and Latin America; low natural gas storage inventories in Europe; and reduced LNG supply "because of planned and unplanned outages at LNG export facilities in several countries." ●

Contact Kristen Nelson at knelson@petroleumnews.com

● EXPLORATION & PRODUCTION

Glacier restarts West McArthur production

CIE gets approval from Alaska's Division of Oil and Gas to extend West McArthur River, Redoubt units to April 30, 2022

By KAY CASHMAN
Petroleum News

Cook Inlet Energy, or CIE, a wholly owned subsidiary of Glacier Oil and Gas, restarted its West McArthur River production on Oct. 25, after previously restarting Redoubt, its other West Cook Inlet unit. Both offshore oil fields had been shut down since May 2020.

Production at West McArthur River was reinstated from two wells, WMRU-05 and WMRU-06.


STEPHEN RATCLIFF

Collectively the two WMRU wells are "contributing an additional 500 barrels of oil per day and remain strong. We remain encouraged about the asset in addition to finishing out 2021 in a healthy position," Glacier President Stephen Ratcliff told Petroleum News in an email Nov. 9.

Glacier put the Redoubt unit back online Sept. 28, with output at 1,200 barrels a day, Ratcliff told PN Oct. 7.

At that time, he said the West McArthur River unit would be back online sometime in November. WMRU was expected to give Glacier's Cook Inlet oil output a "300-500 bpd uptick."

CIE told Alaska's Division of Oil and Gas on Sept. 29 that as part of its restart plan it brought its personnel onsite to its "West Side operations at the end of July," referring to its Osprey Platform in the Redoubt unit, onshore Kustatan Production Facility and the West McArthur River unit.

"The wells, facility, pipelines, and associated infrastructure were thoroughly checked in accordance with state and federal regulations and were systematically brought online," CIE said.

On Oct. 26 requests from CIE to extend Redoubt's 20th plan of development and WMRU's 29th POD until April 30, 2022, were approved by the division.

CIE filed the requests on Sept. 30. They were the second POD extensions for both the units.

Redoubt and WMRU's plans of development were originally set to expire on April 30, 2021. However, due to complications arising from Covid-19, the division approved CIE's application for suspensions of operations and production, or SOPs, for both units on June. 4.

In its request to extend the PODs to April 30, 2022, CIE said it needed the additional time to transition to normal operations and develop plans that would depend upon performance of existing wells within the units that had been shut-in for more than a year and a half.

On March 16 of this year, CIE requested extensions of both unit's SOPs and PODs for one year, citing the global condition of low crude oil prices combined with the lack of demand as justification. The division approved these extensions on April 23. However, in its decision, the agency modified the term of the initial extensions to six months, expiring on Oct. 31.

Furthermore, the division imposed additional modifications to the extensions, requiring CIE to provide updates on the status of Redoubt and WMRU by July 31.

On July 8, the agency received notification from CIE of its intent to restart the Redoubt unit, followed by the WMRU.

In its request to extend the PODs to April 30, 2022, CIE said it needed the additional time to transition to normal operations and develop plans that would depend upon performance of existing wells within the units that had been shut-in for more than a year and a half.

The company also said the extension would re-align the Redoubt unit and the WMRU with their normal POD cycles. ●

Contact Kay Cashman at publisher@petroleumnews.com

continued from page 4

RIG COUNT

October, followed by Asia Pacific with 190, Latin America with 154, Europe with 104 and Africa with 79.

The U.S. rig count averaged 538 in October, up 30 from September's count of 508 rigs, and up by 258 from October 2020, while the Canadian count for October averaged 166, up by 13 from a September count of 153 and up by 86 from October 2020.

Worldwide the rig count was 1,504 in October, up by 56 from 1,448 counted in September and up by 488 from a count of 1,016 last October. ●

Contact Kristen Nelson at knelson@petroleumnews.com

LAND & LEASING

AIDEA sues over leases won in ANWR sale

The Alaska Industrial Development and Export Authority has sued the federal government over the Biden administration's "unlawful actions to obstruct and delay the development of valid oil and gas leases" in the coastal plain of the Arctic National Wildlife Refuge.

After leasing was authorized by the previous administration in the Tax Cuts and Jobs Act in 2017, the Bureau of Land Management held an oil and gas lease sale in the area in late 2020 in which, AIDEA said, it "was the primary bidder and secured seven tracts totaling 365,775 acres for 10-year lease agreements with the BLM effective January 1, 2021."

On his first day in office, President Joe Biden "issued a moratorium on the whole thing through an executive order," AIDEA Board Chair Dana Pruhs said in a Nov. 4 statement on the lawsuit. "I don't like the idea of turning our nation's energy security over to Russia, Iran, and Venezuela," Pruhs said.

The suit, filed in U.S. District Court for the District of Alaska, cites violations of "AIDEA's valid and enforceable leases acquired during the BLM's 2020 lease sale," the agency said.

—PETROLEUM NEWS

● FINANCE & ECONOMY

OPEC+ keeps cautious monthly increases

BY DAVID MCHUGH & JOSH BOAK
Associated Press

OPEC and allied oil-producing countries rebuffed pressure from U.S. President Joe Biden to pump significantly more oil and lower gasoline prices for American drivers, deciding Nov. 4 to stick with their plan for cautious monthly increases even as prices surge and the global economy is thirsty for fuel.

The OPEC+ alliance, made up of OPEC members led by Saudi Arabia and non-members led by Russia, approved an increase in production of 400,000 barrels per day for the month of December at an online meeting.

The OPEC+ alliance, made up of OPEC members led by Saudi Arabia and non-members led by Russia, approved an increase in production of 400,000 barrels per day for the month of December at an online meeting.

That is in line with the group's road map to add that amount of oil to the market every month into next year. The plan is to open the petroleum taps bit by bit — even as oil prices have surged to seven-year highs — until deep production cuts made during the coronavirus pandemic are restored.

That hasn't gone down well with Biden, who has made repeated calls to pump more oil. The U.S. used the Group of 20 summit at the end of October in Rome to consult with other oil-consuming countries on how to exert influence over the producing countries and what they might do if the Saudis and Russians continue to hold back.

"Our view is that the global recovery should not be imperiled by a mismatch between supply and demand," a White House National Security Council statement said Nov. 4. "OPEC+ seems unwilling to use the capacity and power it has now at this critical moment of global recovery for countries around the world."

Focus on 'market stability'

Saudi Energy Minister Prince Abdulaziz bin Salman said member countries were "underscoring their commitment to market stability."

He said OPEC+ was serving as a responsible market "regulator," comparing the relative stability of the oil market to the wild swings in prices for natural gas, which have risen more than five times what they were at the start of the year amid a global fossil fuel crunch.

"Markets need to be regulated, or things may go astray as we have been seeing over the past four months," he said at a news conference.

The caution from OPEC+ means higher prices worldwide and more revenue for producing countries. Slower increases also mean less risk of increasing production too fast and sending prices suddenly lower as the group braces for the possibility of more economic turbulence from COVID-19 outbreaks this winter or from supply chain backups, labor shortages and rising consumer prices that have threatened the global recovery.

Russian Deputy Prime Minister Alexander Novak said the alliance considered "the pluses and minuses," including higher reserves in some countries, the seasonal drop in demand in winter and the impact of the delta variant.

Suhail Almazrouei, energy minister of the United Arab Emirates, said oil markets were expected to be in surplus by early next year and that the gradual road map "is taking us smoothly to that position" where supply and demand would "rebalance in the first and second quarters."

US prices eased

U.S. oil prices eased somewhat the week of Nov. 1 after hitting their highest level since 2014. Oil traded up 0.6%, at $81.39 per barrel, on the New York Mercantile Exchange after the OPEC+ decision, down from its recent peak of over $85 the last week of October. International benchmark Brent crude traded at $82.74 Nov. 4, down from over $86 the previous week.

Oil prices fell ahead of the meeting on speculation that the U.S., possibly in coordination with other countries, could try to quell the recent price rally by releasing crude from strategic reserves.

Biden the week of Nov. 1 blamed higher oil prices on refusal by Russia and the OPEC nations to increase production. He declined to say what steps his administration would take but hinted that additional actions were coming.

"We'll see what happens on that score, sooner than later," Biden said.

The White House statement reiterated that Nov. 4 without giving specifics, saying "we've been in conversations with energy consumer countries and we will consider the full range of tools at our disposal to bolster resilience and public confidence."

Biden is seeking more oil to lower gas prices for U.S. drivers while also pledging at the U.N. climate summit in Scotland the week of Nov. 1 to reduce emissions from such fossil fuels to curb climate change. He even called out Russia and Saudi Arabia during his time in Europe for not doing more to address climate change.

The president acknowledged the irony at the end of the Group of 20 summit in Rome, saying that "on the surface" it does "seem inconsistent." But Americans need to be able to commute to work and moving to renewables will take time, Biden said.

He said it was "just not rational" to "move to renewable energy overnight."

The steady rise in U.S. gas prices has eased in recent days as the typical post-summer drop in demand was delayed this year, according to motor club federation AAA.

The average U.S. price of gas rose to $3.40 a gallon, but the 2-cent rise over the past week is the smallest weekly increase in a month. AAA predicted that elevated crude prices will likely keep pushing up gas prices as long as oil prices are above $80 per barrel. ●

● EXPLORATION & PRODUCTION

Hilcorp applies for Granite Point UIC permit

By KRISTEN NELSON

Petroleum News

Hilcorp Alaska has applied to the U.S. Environmental Protection Agency for a permit for a Class I nonhazardous injection well at the Granite Point platform in Cook Inlet, EPA said in a Nov. 9 notice.

EPA said it proposes to issue an underground injection control Class I nonhazardous permit allowing Hilcorp to inject waste through an existing well, GP 44-11, which has been used to inject similar waste to that proposed under the permit into the same geological formation for more than 25 years under a UIC Class II permit from the Alaska Oil and Gas Conservation Commission.

The EPA permit will change the well from Class II to Class I, allowing the injection of nonhazardous fluids from the platform, in addition to the produced water allowed under the Class II permit.

EPA said Class II wells are used to dispose of water brought to the surface from oil and gas production operations, to enhance recovery of oil and gas or to store hydrocarbons liquid at standard temperature and pressure.

"Class II wells differ from Class I wells in the construction, operation, and monitoring requirements, as well as the range of waste streams that may be injected. Operators can only use Class II wells to inject waste that is associated with hydrocarbon production," EPA said.

Historic injection

Underground injection at Granite Point began in 1968 and more than 163 million barrels have been injected at the field. EPA said it exempted the aquifer underling the entire Granite Point field from status as an underground source of drinking water in 1984, an exemption applying only to Class II injections.

Hilcorp operates two Class II wells on the Granite Point platform, GP 44-11 and GP 24-13RD2; EPA said the company will continue to operate GP 24-13RD2 as a Class II well.

When a Class I permit is issued, Hilcorp could use GP 44-11 to inject both produced water and other exempt or nonhazardous waste streams, including but not limited to "liquids associated with the operation and maintenance of an oil and gas platform, storm water, domestic wastewater, drilling cuttings and muds, and produced water."

EPA said under the proposed action it would modify existing exemptions for a portion of the aquifer underlying the Granite Point field, specifically the interval from 4,865 to 5,411 feet true vertical depth and within a 5,726 feet radius from the platform, allowing the aquifer to be used for Class I wastes.

Comments are being taken on the proposed permit from Nov. 9 through Dec. 9 at 5 p.m. Alaska time. ●

Contact Kristen Nelson at knelson@petroleumnews.com

UTILITIES

RCA to monitor electric utilities' gas supplies

The Regulatory Commission of Alaska has decided to issue an order, requiring electric utilities in the Alaska Railbelt to report annually on their future needs for and anticipated supplies of natural gas for power generation. The order comes as part of a commission docket addressing the reliability and security of the electrical system. Much of the electricity supplied in the Railbelt comes from gas-fired power generation, using natural gas produced from the Cook Inlet basin.

In a Nov. 10 public meeting the RCA passed a motion to issue the order, requiring each utility to file a report on Jan. 31 each year, starting in 2022. A utility must report its projected annual power needs for the next 10 years, to meet its customers' demand, and the projected natural gas supply requirements to support that demand. The report must also include the utility's projected gas supplies from each approved gas sales agreement or from other firm gas supply sources.

There is also a reporting requirement for three-year projections of economy energy sales — the sale of power from one utility to another — and the projected gas supply needs and sources to support those sales.

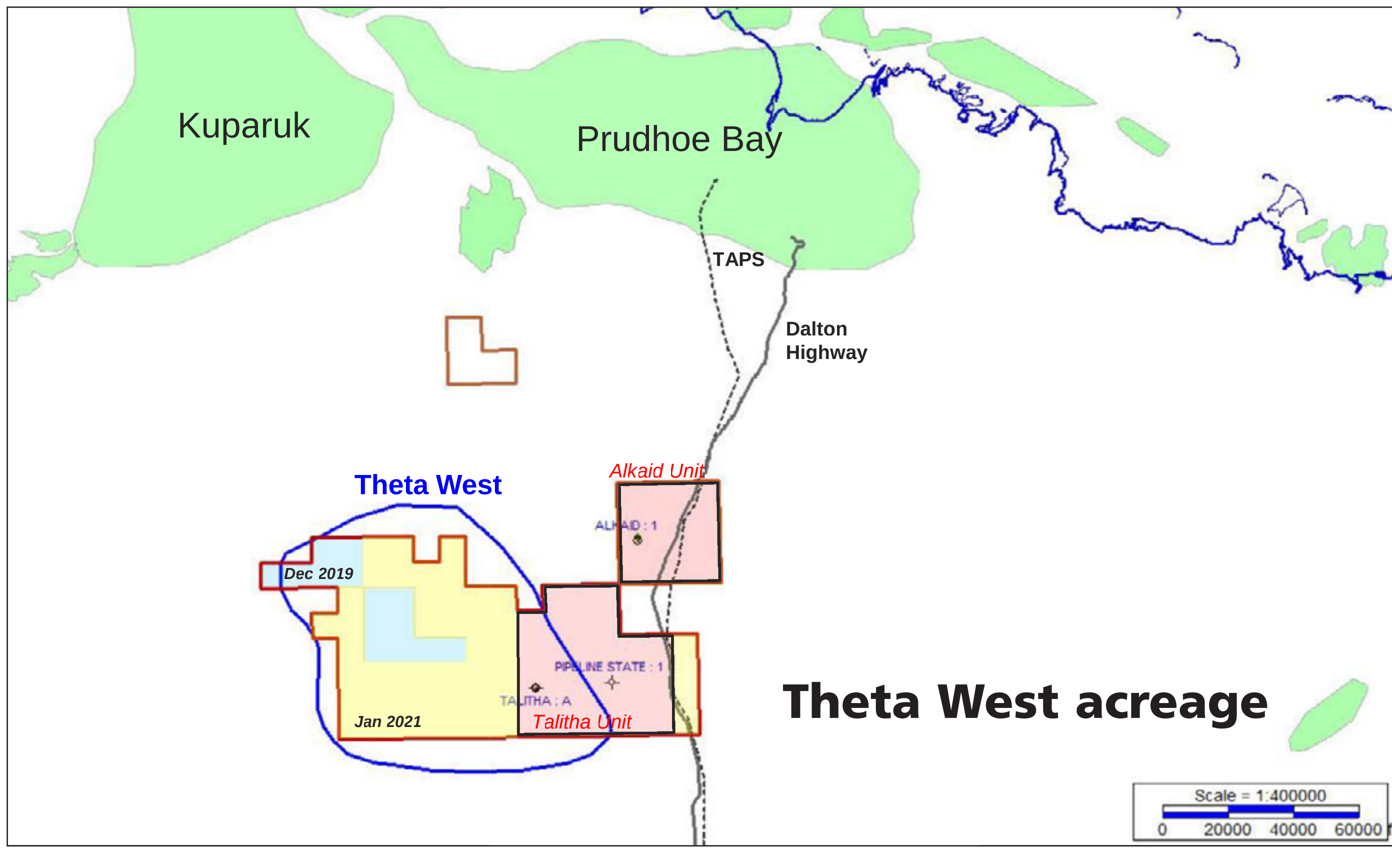
Beginning in 2023 the reports must also include a reconciliation for the previous year of the actual power used relative the projected power needs, and a reconciliation of the actual gas used relative to the projected gas requirements.

An order will also address the frequency of reporting of economy energy sales between the utilities. In 2019, as part of a drive to monitor and encourage the pooled use of efficient power generation, the commission required quarterly reports of these sales. The new order will reduce the reporting frequency to twice per year. Commissioner Antony Scott commented that the economy energy market has changed significantly in recent years, with the use of pooled transactions increasing in importance. Chugach Electric Association has acquired Municipal Light and Power to form a single Anchorage-based utility; Chugach Electric and Matanuska Electric Association are implementing an agreement to form a tight power pool; and only one utility, Golden Valley Electric Association, now makes significant numbers of economy energy purchases, Scott said.

—ALAN BAILEY

continued from page 1

THETA WEST



PANTHEON RESOURCES

"This discovery would be significant anywhere in the world, whether in 5,000 feet of water, or Alaska or Texas; it would have a massive, major impact," Rosenthal said. "It's proximity next to infrastructure just magnifies that impact."

The Talitha well lies just to the west of the Dalton Highway haul road and the trans-Alaska pipeline system, about 20 miles south of the Prudhoe Bay oil field. The road and the pipeline pass through the company's acreage.

"Our discoveries, as we've repeatedly said, extend underneath the pipeline," Rosenthal said.

Theta West updip from Talitha

While the Theta West prospect is conventional, the route to the drilling of the Theta West well is unconventional. Theta West 1 is updip from the Talitha discovery well.

"Its updip by a couple of thousand feet, maybe 2,500 feet," Cheatham said. "Normally of course you drill on the crest of the structure and then you'd start doing your appraisal well downdip; well, we drilled the downdip portion and we're going to do our appraisal well in the updip."

GBP is committed to extensive testing in the downdip Talitha well.

"I happen to think that that was a very gutsy move on our part because if we hadn't found hydrocarbons there, if we hadn't found reservoir at that location it would have been hard to go raise the capital to drill the optimum location or close to the optimum location, which would have been updip, where we're going to appraise it," Rosenthal said. "But we did, and so when we drill Theta West and appraise it up there, we're going to have two wells already, one in the crestal position, and one — which is Talitha — in the way downdip position to say we've got hydrocarbons over a huge distance."

The company was surprised to find a 3,700-foot oil column there in the Talitha A well; it had expected to see 2m000 feet, Cheatham said.

In the Talitha well, in the Lower Basin Floor Fan the company encountered 600 feet of about 60% net-to-gross, according to Rosenthal, adding, "We hit another succession in what we call the Upper Basin Floor fan that sits right above the hue shale."

GBP expects even better results in the Theta West well.

"We believe the fan will be double the thickness, maybe more, and of better quality, closer to the source," Cheatham said, adding that the crest is at about 7,500 feet.

"To get through it — it's such a thick section, we'll probably TD at about 9,500 feet," Rosenthal said. "It's going to be significantly shallower than what we drilled at Talitha, 2,000 feet or so shallower, significantly less depth of burial so less degradation of the reservoir."

"What we have are these fan successions just stacked one right on top of the other, like five or six of them, and when we drill Theta West, we expect to have more of them," he said. "There's a geologic reason why these things are stacked right where they are, we're seeing these big, stacked successions of these individual fan complexes one right on top of another and its about 50-60% net to gross."

Fast track to development

The Theta West well, close to the crestal position, and Talitha well downdip will provide a clearer picture of the geology, Rosenthal said.

"With that, and our third data set, and the seismic petrophysics that we've been doing, I think we'll have a case to take to the state to let us start building out a development plan," he said. "This is an appraisal well; we drill it, and we test it. I think we can take it to the state and ask them to help us get this on production."

GBP is not looking to build a massive central production facility at Theta West; it will build out in increments.

The development will require hundreds of wells, Cheatham said.

"We plan to use these mobile arctic production systems that come in about 5,000-6,000 barrel a day increments — think of it as skid mounted units, we could plug them in as we're developing," he said. "We don't have to do all this front-end engineering and design to completely optimize your production to squeeze the last dollar of present value out of it."

The design will minimize the need for pipelines throughout the development.

"These are production units where you treat your oil on site," Cheatham said. "That also is what allow us to not have so much piping when we're going to reinject our effluent back into the reservoir."

GBP will use horizontal wells from a single pad, for efficiency of land use, and better recoveries, he said.

"We're going to do horizontal wells and multi-stage frack into all of these reservoirs," Rosenthal said.

"We will need water for the fracks, and we have looked at water resources and we think there's plenty of water resources nearby," Cheatham said.

"We believe that once we got the go ahead from the state, in a couple of years we could be on production, and peak … from a fairly conservative model we're speaking around 90,000 barrels per day for Theta West," he said.

The company has additional development in mind.

"That's just one out of two or three, we've got a couple other developments we could do too," Rosenthal said. "The Alkaid development along the Dalton Highway that we mentioned earlier, could be super early production, and then our shelf margin deltaic in both of our units, our Talitha unit and our Alkaid unit — and part of that is developable from the highway."

"We believe we can be a big player pretty quickly for the state of Alaska," he said. "We're so pleased that we are 100% on state land."

Respect for the environment

GBP plans to develop as it has explored, with a minimal effect on the environment.

see **THETA WEST** *page 10*

continued from page 9

THETA WEST

"Since we are a greenfield project, we are going to endeavor to — after we're in a development phase — capture all of our emissions and reinject, so we will burn the associated gas to generate electricity; we'll use all-electric frac pumps, all-electric rigs, etcetera, and capture the CO2 and reinject it back into the reservoir, that's our plan," Cheatham said.

GBP considers Theta West 1 to be an appraisal well of last winter's discovery at Talitha...

Reinjection of the carbon dioxide is likely to enhance oil recovery.

"It should help, a little pressure maintenance can't hurt," he said.

"We haven't modeled it, but of course if you look at Prudhoe Bay, they're getting those great recoveries in part because they have not only water injection but also the gas pressure maintenance — the reinjection of the gas," Cheatham said. "CO2 is used certainly in reservoirs in west Texas as early as the 1950s."

Any unburned natural gas would also be reinjected.

"We would not have any emissions," he said.

PANTHEON RESOURCES

Talitha A exploration well

Rosenthal, one of the founders of Great Bear, which merged with Pantheon in 2019, said the company historically had an environmental focus.

"You might remember several years ago we did a massive thing called a Lidar study up on the Slope," he said.

The company used airborne laser analysis for water resources, to look at all the lakes in the area — noting lake depths, which lakes had fish, and which did not.

"One of the primary reasons we did that one is that we can do a big area, but the other is that you minimize your impact," Rosenthal said. "The only other way to do that is to send out crews and measure it, so you're going out on the tundra."

Great Bear showed that the method worked well, leading it to do additional airborne Lidar studies.

"When the Sag River flooded, I believe the state went to that Lidar study — which we gave them — and used that to understand what the original river channel looked like so they could use that in terms of rectifying the problem."

Farm in partner in discussions

GBP has made no secret of its search for a farm in partner to share the cost of development.

"What we can say is we're quite advanced on discussions with bringing in a farm in partner; we're confident that that will happen," Cheatham said. "We're planning on drilling this winter; we're looking for a partner to come in and partner for the whole thing, that's what our discussions are right now."

The company has a backup plan.

"We have to have either a farm in partner or some other method of financing," Cheatham said. "We do not have enough capital to drill the Theta West well, so we've been going down multiple parallel paths for the last several months, and we're quite confident."

Pantheon is listed on the AIM portion of the London Stock Exchange, but it is small and nimble.

"Our Anchorage staff is three, and we have a couple of consultants," Cheatham said.

Cheatham said the stacked pay found in the Talitha A well is important.

"Starting at the bottom is the Kuparuk, then the two basin floor fans, then we got a couple of intervals we call the slope fan system that we think are highly prospective, and then the Shelf Margin Deltaic," he said. "Our imaging of the Shelf Margin Deltaic changed dramatically after we drilled the Talitha well and got this great data."

There is enormous resource density in the company's acreage, Cheatham said.

"To date, we have 16 or 17 billion barrels of oil in place without counting all of the reservoirs," he said. "We think close to 2 billion barrels recoverable." ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

continued from page 1

TRUDEAU IN GLASGOW

acknowledgement that many of his measures must be negotiated with the provinces who control development of their natural resources.

Neither did he deliver any commitments to match the penalties he is imposing on energy producers with similar levies on the end users of fossil fuels in the industrial heartland of Ontario and Quebec, where voters have played the key role in keeping his Liberal Party government in power over the last six years.

Other carbon sources

Although the oil and gas sector is estimated to contribute 200 million metric tons a year of carbon to Canada's atmosphere, Trudeau has never mentioned the 190 million metric tons generated by the transportation industry.

When newly appointed Environment Minister Steven Gilbeault warned about the impending emissions cap on the petroleum industry he said similar measures were not planned for the steel, auto, forestry and cement sectors.

JASON KENNEY

"We're doing it for oil and gas because it represents 25% of emissions in Canada," he said, apparently unaware that he used the word "for" as if the government was delivering a favor.

Many observers are now convinced that Trudeau is determined to punish producers rather than users of fossil fuels feels — a prospect that outrages the upstream industry whose leaders have demonstrated their desire to play a key role in tackling climate challenges.

In casting himself in Glasgow as a global trailblazer, Trudeau tried to put on a tough-guy image in a two-minute address to his global peers by demonstrating he will not buckle under pressure from the petroleum industry.

Canada will, he declared, "cap oil and gas emissions today and ensure they decrease tomorrow at a pace and scale needed to reach net-zero by 2050. That's no small task for a major oil and gas producing country. But it's a big step that's absolutely necessary."

Commitment to lower methane

A day later, having failed to get other leaders to follow Canada's example on a carbon tax, he played another of his key cards by committing his administration to lower methane gas emissions by 75% before 2030, compared with the 30% goal set by more than 100 other countries.

Again, he failed to acknowledge that the provinces of Alberta, Saskatchewan and British Columbia agreed a year ago to reduce methane emissions by 45% by 2025, then accelerate the pace of shrinking emissions after that.

What infuriates Alberta Premier Jason Kenney, who declined to attend what he called the "Global Gabfest in Glasgow," is Trudeau's efforts to ride roughshod over the Canadian Constitution, which assigns ownership and the development of natural resources to the provinces.

He said "the Government of Canada has zero chance of achieving its greenhouse gas emission targets without Alberta, specifically without Alberta's oil and gas industry."

He called it peculiar that Trudeau hadn't discussed the issue with the province before he spoke at COP26. "We need to be partners in this," he said.

Kenney noted that his government has already imposed a carbon price of C$30 per metric ton on greenhouse gas emitters and is ready to raise that tax if it fails to achieve the desired results.

The Trudeau government carbon tax began at C$20 per mt in 2019, is C$40 now (amounting to 8.8 cents per liter of gasoline) and is expected to reach C$170 by 2030.

Hardened bargaining line

However, Trudeau hardened his bargaining line when he noted that only about 20% of global carbon emissions are taxed, a figure he believes must rise to 60% by 2030 if there is any hope of reaching net-zero by 2050.

"We should be ambitious and say, as of right here today, that we want to triple that to 60%," he said.

The industry's response to this federal piling-on exercise has been to open its door to negotiations, while seeking federal assistance to pay for what an alliance of the six oil sands heavyweights (Suncor Energy, Cenovus Energy, Canadian Natural Resources. Imperial Oil, MEG Energy and ConocoPhillips Canada, who account for 95% of oil sands output) estimates will cost C$75 billion over the next three years to curb emissions.

Alberta has called for at least C$30 billion in federal incentives over the next decade.

Cap on emissions

Cenovus Chief Executive Officer Alex Pourbaix said the alliance, known as Oil Sands Pathways to Net Zero, is "not particularly fussed by a cap on emissions, subject to a couple of provisos. Those caps must correspond to the industry's ability to actually, physically reduce its GHG emissions. These are things that cannot be done overnight."

Pourbaix also believes a price on carbon must be applied globally.

He noted that the industry is "pretty aligned with the federal government. They have set a net-zero target for 2050 and that's the same target we have come out with."

But Pourbaix said he expects that "on a go-forward basis, you will continue to see growth that will be a lot more measured."

Kenney is taking an even harder line, insisting his government will fight any anti-oil push to keep fossil fuel resources trapped underground.

In a parting shot to an industry that is a key economic driver in Canada, the Trudeau administration signed up with 23 other countries at Glasgow to cut government subsidies by the end of 2022 to help companies operate and explore outside their home countries and pledged to direct those funds to clean energy development.

If all of the countries live up to their commitment the policy could transfer about US$15 billion a year out of fossil fuels (about C$1 billion from Canada) into clean energy.

Natural Resources Minister Jonathan Wilkinson said there is an "urgent need to reduce emissions in every sector of the economy, everywhere in the world."

He said the Trudeau government will now work on ending subsidies for its domestic oilpatch, although it has yet to set a specific date. ●

Contact Gary Park through publisher@petroleumnews.com

continued from page 1

ALTERNATIVE SETBACKS

The Mi'kmaq First Nation set up a year-round protest camp at one of the work sites after objecting to plans to flush out large underground salt deposits, dumping leftover brine into a tidal river that has served the Indigenous population for thousands of years.

Almost three years ago, the Canadian government said it would regulate the project to manage potential threats to fish, fish habitat and human health, but that failed to satisfy the Assembly of Nova Scotia Mi'kmaq Chiefs.

Nova Scotia Natural Resources Minister Tory Rushton said he was unable to speculate on why the company made its decision, but said he is hopeful other companies will fill the void.

The C$130 million plan involved building up to 15 caverns to feed gas into the Maritimes and Northeast gas pipeline 40 miles north of Halifax.

The other setbacks have involved wind farm projects, in Alberta and New Brunswick.

Buffalo Plains Wind Farm has plans to erect 83 wind turbines on 17,500 acres of privately owned farmland almost 100 miles southeast of Calgary.

But the project is facing strong opposition at a hearing that is underway by the Alberta Utilities Commission. The resistance comes from residents who are already unhappy with the impact of 26 turbines operating in their area.

According to developer ABO Wind, landowners in the immediate area qualify for some royalty payments, but many residents are unhappy with impact of the existing operation.

Spokeswoman Lavinia Henderson said the turbines, which are bigger than most at a height of 660 feet, are loud and produce a "shadow flicker" which occurs when the sun casts a moving shadow as it shines through the rotating blades.

The utilities commission said social, economic and environmental effects are all included in its project hearings, but ABO Wind declined to comment while the review is taking place. A decision is expected in February.

A second wind farm in New Brunswick has been taken offline after one of its turbine towers collapsed.

Calgary-based TransAlta said the tower is among 55 at its 167-megawatt facility.

It said that until the cause of the collapse is determined it will be unable to return the site to full service.

—GARY PARK

Contact Gary Park through publisher@petroleumnews.com

continued from page 1

PLACER SALE

Kuparuk C anchor

Back to the fifth POD for the Placer unit.

The long-range proposed development activities for Placer, AEX told the division in its Oct. 2, 2020, filing, include plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established.

AEX identified Kuparuk C as the anchor productive interval within the Placer unit, planning to develop the reservoir with two horizontal multi-stage fracked producers and two injectors for optimal sweep.

Earlier in 2020, AEX received the 404 U.S. Army Corp of Engineers permit to build a gravel pad near the Placer 1 well location which will be accessed via gravel road. A three-phase pipeline will transport fluids from Placer to the Mustang facility, if that turns out to be the facility that will process Placer oil.

Enter the Nanushuk

A G&G evaluation of other plays in the Placer unit was included in the Oct. 2, 2020, POD filing.

AEX said it had "evaluated oil shows from Nanushuk sandstones encountered" in the Placer 1 and Placer 2 wells.

"Our seismic interpretation of the merged, reprocessed, 3D seismic data over the Placer unit indicates a major change in the basin architecture between the Nanushuk 3 development in the Pikka unit and the Placer unit. The sand development in Placer 1 and 2 wells is related to a backstepping transgressive system. AEX has continued the analysis of the Nanushuk interval because it could be a potential satellite development from the Placer unit," AEX said.

In the company's initial evaluation, "two apparent log facies in the gamma ray of nearby wells were noted. AEX mapped two anomalies referenced as Western Nanushuk and Eastern Nanushuk."

AEX pointed out that on Jan. 22, 2020, a press release from Oil Search Alaska, "announced 197 feet of net pay with 180 feet of oil pay and 17 feet of gas in their Mitquq 1 well. The surface location for the Mitquq wells (1 and 1ST1) are located approximately a half a mile east of the Placer unit boundary and targets the same trend AEX had previously identified."

Public well results from Mitquq 1 "appears to have validated AEX's asserted interpretation of the Nanushuk interval and has de-risked the Nanushuk in the eastern part of the (Placer) unit."

Scenario for Eastern Nanushuk

Based on results from its G&G analysis of the Eastern Nanushuk, AEX said it was reviewing its Placer unit development plan and had "concluded that the Eastern Topset can be reached from the Placer 1 drill pad."

In the Placer 404 permit AEX designed the drill site to be large enough to accommodate additional wells.

The company said it "has constructed a high-level reservoir model for the Eastern Nanushuk (Topset) and the Western Nanushuk (Topset) within the Placer leases." AEX said it plans to include these prospects in its future development plan. Also, as part of its Kuparuk C drilling plan, wells with pilot holes will be extended to test the Alpine C, which one well known and respected North Slope geologist told Petroleum News looked "sweet" on 3D seismic.

Quarterly reports

In a first quarter Placer update to the division on April 2, 2021, AEX President Chait Borade told division Director Tom Stokes that as the division knew "AEX has been in the process of divesting its interest in the Placer unit since Jan. 1, 2021."

Borade also said, "AEX closed on its transaction for the sale and transfer of the Placer unit leases on March 29, 2021."

He listed the following activities that AEX had committed to for Placer's fifth POD for first quarter 2021:

- Start permit application process for ADEC (DAQ, DEH, SPAR), ADF&G (Title 16), ADNR (DMLW, SPCO) & AOGCC state permits in Q1, 2021.
- Restart discussions with the North Slope Borough regarding NSB Title 19 Rezone.
- Start permit applications for USACE, EPA, USDOT, USFWS Federal permits.
- Obtain master service agreements with contractors for ice road, civil, and gravel during Q1 and Q2 2021.

In light of the sale, Borade asked Stokes for guidance from the division regarding which of the activities under the fifth POD, if any, AEX should continue to pursue "while the lease assignment applications are pending" — i.e. await approval from the division, along with a proposed 6th POD from the buyer.

Interest waning Mustang?

In AEX's progress report for the second quarter, April 1 to June 30, 2021, the company said that since the "Mustang facility is in an indefinite cold shutdown … AEX will formulate and provide the division with an alternative plan for facility access for Placer unit production on or before June 30, 2021."

On Oct. 15, AEX requested a six-month extension of the Placer unit's fifth plan of development, which ends Dec. 31, to allow it enough time to "determine how best to advance development of the Placer unit prior to submission of the proposed 6th POD."

The state's interests are protected because AEX had previously posted a $1 million performance bond which won't be released back to AEX unless AEX establishes sustained unit production at the Placer unit by Oct. 31, 2022.

As of Nov. 10, the division had not yet posted its decision. ●

Contact Kay Cashman at publisher@petroleumnews.com

continued from page 1

BRADLEY LAKE

director, has told Petroleum News.

"The feasibility side of it is going to take at least two to three years," Thayer said.

The Bradley Lake facility is located on the south side of Kachemak Bay, at the eastern end of the bay. In addition to being a renewable energy source, the facility provides the cheapest electricity in the interconnected Railbelt electrical system. However, its power output is limited by its total hydro capacity, which relates to the amount of water flowing into Bradley Lake.

Development options

Meltwater from the Dixon Glacier flows into a large lake below the glacier terminus, with water from the lake flowing into Martin River. AEA has been investigating the possibility of diverting water originating from Dixon Glacier into Bradley Lake, in a similar manner to the way that water is now diverted from Battle Creek, Thayer said. Another possibility would be to place a run-of-river turbine generator in Martin River, to boost power output from the Bradley Lake powerhouse. A third possibility would be to both install a run-of-river generator and divert water to Bradley Lake, Thayer said.

Although acquiring the necessary permits will be a critical factor in the timing of a development project, the fact that the water system involved all sits within state land simplifies the situation. With Gov. Mike Dunleavy encouraging AEA to seek renewable energy opportunities, AEA is working with the Railbelt electric utilities to investigate this further possibility for Bradley Lake expansion, Thayer said. AEA has applied for water rights, is investigating Federal Energy Regulatory Commission jurisdiction over expansion possibilities and is looking into the installation of water gauges in Martin River, to determine the flow of the river, he said.

AEA is working with the utilities on options for upgrading the transmission system — although this is a separate exercise from any Bradley Lake expansion, the potential to expand the hydropower facility does provide more reason for transmission system upgrades, Thayer suggested.

Modifications to dam?

If water originating from Dixon Glacier is diverted into Bradley Lake, the height of the current dam at the lake would probably have to be elevated — it would be possible to raise the height of the dam by 28 feet. A further possibility would be the installation of a third generator in the powerhouse at a cost of around $75 million. Apparently, the powerhouse was designed to accommodate three generators, although only two generators have actually been installed.

Ultimately, everything will depend on the water flow situation — there is the potential to increase the Bradley Lake power capacity by 50% or more, depending on which of the three development options is selected. However, the water flow into Bradley Lake is seasonal, with the flow being lower during the winter than at other times of the year.

The transmission system

Obviously the electrical transmission system on the Kenai Peninsula would need to have sufficient capacity to handle any additional power output from Bradley Lake. All of the Railbelt utilities make some use of Bradley Lake power, which is shipped north over the Railbelt transmission network. Last year AEA purchased from Homer Electric Association the transmission line segment between Sterling and Quartz Creek, a critical line in the transmission of power from the peninsula. AEA is working with the utilities on options for upgrading the transmission system — although this is a separate exercise from any Bradley Lake expansion, the potential to expand the hydropower facility does provide more reason for transmission system upgrades, Thayer suggested.

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com

Petroleum news

Oil Patch Bits

Alaska Marine Lines wraps up strong fish season

As reported by Lynden News Nov. 8, "We had a very good seafood year," says Tyler Maurer, Alaska Marine Lines seafood sales manager. The 2021 fish season for Alaska Marine Lines and the supporting Lynden companies has been strong. Alaska salmon runs were 15% higher than projected, and the Bristol Bay sockeye salmon run stunned scientists with a record 66.1 million fish, with a catch of approximately 40 million which was 90% of the record 44 million.

At Lynden, salmon season is an "all hands on deck" event typically lasting from May through September. All Lynden companies were busy keeping up with the volume this year, prompted not only by larger returns, but by restaurants opening back up after pandemic closures and a change in consumer buying habits.

Each year, Lynden Air Cargo flies fresh fish from Naknek, Emmonak, Cold Bay, Sand Point and Dillingham to Anchorage where Lynden Logistics provides support for transloading to Alaska Marine Lines, Alaska West Express and Lynden Transport and ships seafood with other air carriers all over the world. LTI Inc. trucks provide Seattle surface delivery support and provide transportation to locations in the Lower 48.

COURTESY ALASKA MARINE LINES

On average, Alaska Marine Lines moves 7,000 containers of fish each year from Alaska fisheries southbound to Seattle. "We moved over 11,000 containers this year," Tyler explains, "and we still have more frozen and canned product to clean out of Alaska for a few more weeks to come."

To prepare for the push each year, Lynden asks its customers for projections so it can build realistic expectations for staffing and equipment. "We knew this would be a big year," Tyler says. "We just didn't expect it would be this big of a year with all regions having strong returns." For more information visit info.lynden.com/blog.

Companies involved in Alaska's oil and gas industry

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

continued from page 1

OIL SEARCH UPDATE

As Oil Search and Santos continue to advance their proposed $6.5 billion merger., which will be voted on by shareholders on Dec. 7, Oil Search and its Alaska partner Repsol have been each looking to sell 15% of their stake in Pikka to provide funding needed for the phased oil development.

But Fredricson told Dow Jones, "As a merged entity there is less requirement for such a sell-down," which would allow Oil Search to retain more of the value from the oil that is expected to flow from Pikka in the second half of 2025.

This news follows on the heels of unconfirmed rumors that a top Santos executive visited Anchorage in the last few weeks to meet with state officials and management in the Oil Search Alaska office.

Fredricson also said the Pikka sales process has been on the backburner since merger talks with Santos began.

In its Alaska summary GaffneyCline said permits are being obtained for the Pikka unit, Quokka, Kooka, Thetis, Horseshoe Area, Lagniappe and Nanushuk West.

Half-hearted backing

As part of the Santos takeover of Oil Search, an independent expert firm, Grant Samuel & Associates, was hired by Oil Search to advise its shareholders before they voted on the proposed merger.

If it goes ahead, the takeover of Oil Search would create a global top 20 oil and gas company and make Santos the largest shareholder in Papua New Guinea's huge LNG project, which is operated by ExxonMobil.

In a report attached to the 700-page-plus merger document that went to shareholders Nov. 11, Grant Samuel said Santos' offer, which will give Oil Search shareholders a 38.5% stake in the merged entity, did not fully reflect Oil Search's underlying value, which it said was worth 43%-44% of the total value.

"There is clearly a risk that the funding and other strategic benefits do not fully compensate shareholders for this dilution," Grant Samuel said in the report. "On the other hand, the options to maximize the value realized for Pikka and, over time, to optimize the development of its PNG interests are significant benefits of the merger that are not available to Oil Search on a standalone basis."

So, since Oil Search faces real challenges in funding its growth opportunities on a standalone basis and faces "the real possibility that a standalone Oil Search would require equity support from its shareholders to maximize the value of its future development projects, … in the absence of a superior proposal," Grant Samuel concluded that Oil Search shareholders were likely better off if the deal went ahead.

Pikka report

As part of its report to Oil Search shareholders, Grant Samuel appointed GaffneyCline to prepare an Independent Technical Expert's Report on Oil Search's Alaska assets, including the proposed Pikka development.

Although much of what was said in GaffneyCline's report was reported in past issues of Petroleum News, there were some nuggets of new information, along with confirmation of where the Pikka project stands today with its owners, Oil Search, 51%, and Repsol, 49%.

As mentioned, first oil from Phase 1 of the Pikka project is expected to flow in the second half of 2025.

In its Alaska summary GaffneyCline said permits are being obtained for the Pikka unit, Quokka, Kooka, Thetis, Horseshoe Area, Lagniappe and Nanushuk West.

In its "Gross Valuation Scenario Volume" as of July 1, 2021, GaffneyCline wrote: "392 MMBbl Pikka Phase 1 development, 464 Other Development Pending, 112 MMBbl Development Unclarified."

Formed in 2015, the Pikka unit consists of 89 different subsurface leases.

Pikka, operator Oil Search's initial development project, targets oil deposits in the major Nanushuk and Alpine reservoirs. It was re-planned as a phased development to cut costs to first oil.

Phase 1 is only one of the original three drill sites, NDB, with downsized facilities. Its CAPEX estimate has been significantly reduced from $4.8 to $6.1 billion to $2.7 to $3.1 billion.

Gravel has already been laid for the processing facility, NPF, and NDB reducing forward costs.

Oil Search has high graded the project to a better reservoir at NDB. Breakeven cost of supply is now below $40 a barrel.

Oil Search has fully aligned with JV partner Repsol.

FEED entry occurred in February with the final investment decision planned by the first half of 2022 for Phase 1.

The company plans to spud Pikka development wells in July 2022.

Exploration in, outside Pikka

Oil Search acquired new acreage in the January 2021 State of Alaska lease sale as "a conveyor belt for future opportunities," GaffneyCline reported.

In a segment on exploration, the firm said that "in addition to the core project scope, the Pikka development represents an aggregation point for future exploration, both in-field and regional. This includes satellite reservoirs in the Pikka unit, including the Nechelik, Nuiqsut, Kuparuk C, Torok, Tuluvak, as well as other Alpine and Nanushuk leads."

Additional reservoirs are drillable from drill sites NDA, NDB or NDC within extended reach drilling constraints, GaffneyCline said.

"It is anticipated these volumes would be developed during production operations of the Pikka unit. Given the low incremental cost of development, these would be prioritized over new pad developments."

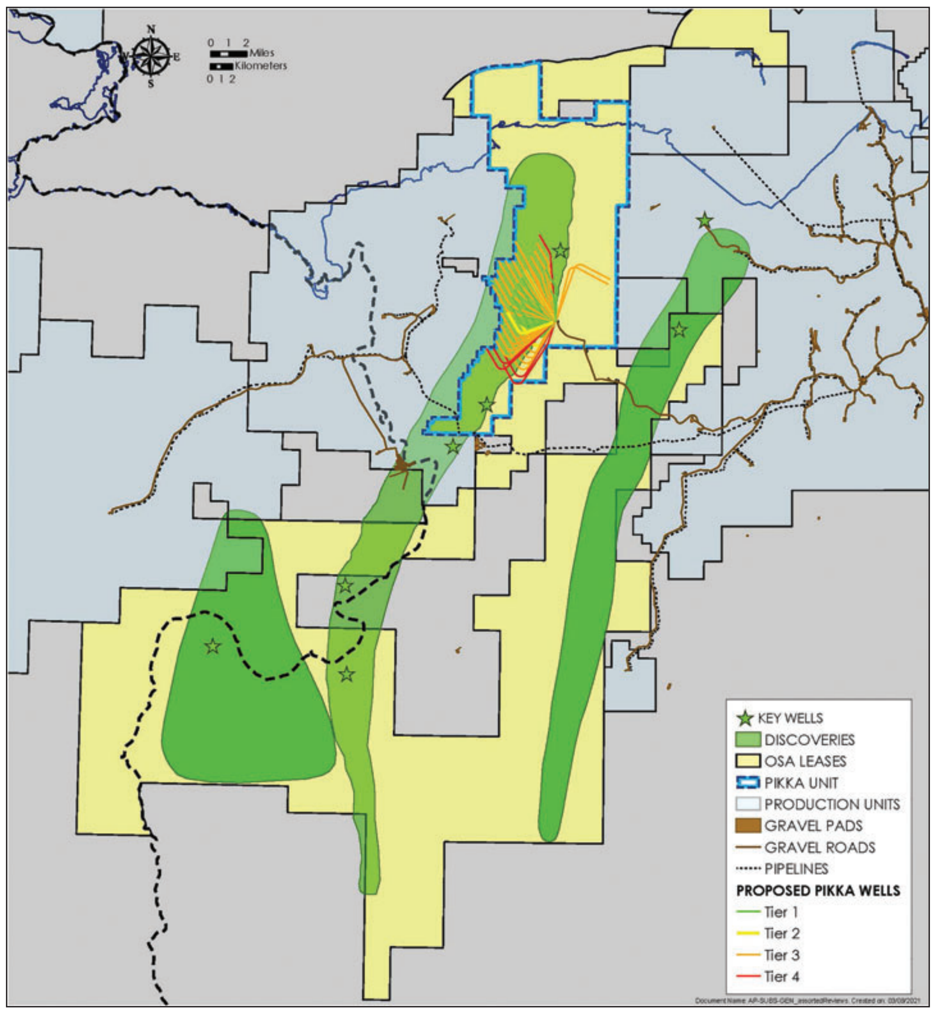
In addition to the reservoirs drillable from NDA, NDB and NDC, "there are potential targets both inside and outside the Pikka unit which would require new pads to be developed. These include Pikka East and Pikka North areas. There are also several discovered and prospective exploration targets at Horseshoe which lie outside of the current Pikka unit," GaffneyCline said, noting they include "three clinoform sands units, Diamond, Red Tail and Sulphur which Oil Search plans to target with a single exploration well."

—KAY CASHMAN

Contact Kay Cashman at publisher@petroleumnews.com

Oil Search Alaska has identified two major new trends (Quokka and Horseshoe/Stirrup) with similar scope and scale to Pikka.

Figure 4.30: Pikka Unit Location



SOURCE: OIL SEARCH

During 2020, the exploration wells Mitquq and Stirrup were drilled with the data and test results fully analyzed including core analyses. The new Mitquq and Stirrup data was incorporated into the static models for subsequent resources estimates. Oil Search identified two major new trends (Quokka & Horseshoe/Stirrup) with similar scope and scale to Pikka.

continued from page 1

OIL PRICES

released from strategic reserves by the Biden administration.

The U.S. Energy Information Administration reported Nov. 10 that U.S. commercial crude oil inventories for the week ending Nov. 5 rose by 1.0 million barrels from the previous week. At 435.1 million barrels, inventories stand at about 7% below the five-year average for this time of year.

Commercial inventories reflected a release of 3.1 million barrels from the Strategic Petroleum Reserve, the largest since July 2017, according to a Reuters report.

Total motor gasoline inventories, on the other hand, decreased by 1.6 million barrels for the week, hovering some 4% below the five-year average for this time of year, the EIA said.

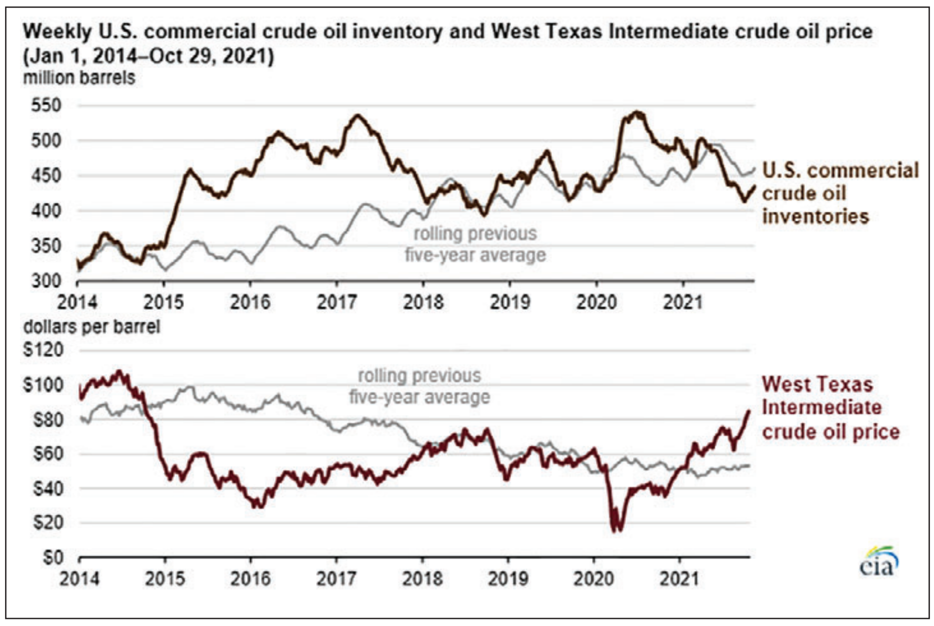
The EIA said in a Nov. 9 report that crude oil demand is returning faster than supply, increasing prices, and reducing inventories.

This year, demand for petroleum, both in the United States and globally, has largely returned to the pre-pandemic levels of 2019, it said, adding that the price of WTI crude oil is near its highest level since 2014.

The price for WTI reached $84 per barrel Nov. 1, up $37 since the beginning of the year.

Refineries have increased operations at a faster rate than U.S. crude oil production has increased this year, contributing to the decline in U.S. crude oil inventories, the EIA said.

In 2019, U.S. crude oil production averaged 12.3 million barrels per day, falling to 9.7 million bpd in May 2020, the EIA said. From Oct. 1 through Oct.



29, 2021, weekly data indicate that U.S. crude oil production averaged 11.4 million bpd.

Aero demand to lift off

Recovery in demand for aviation fuel consistently has lagged the recovery in demand for motor vehicle fuels since the COVID-19 demand shock in April 2020.

While motor fuel demand has returned to pre-pandemic levels, jet fuel demand levels lie some 3 million bpd behind the 7.5 million bpd levels seen in 2029.

Global oil spare production capacity could take a hit in 2022 as air passengers return to the skies, Saudi Aramco CEO Amin Nasser said Nov. 9 in remarks to the Nikkei Global Management Forum.

"The industry's spare capacity, currently at 3-4 million barrels per day is providing some comfort to the market, however, my concern is that the buffer ... might diminish, especially next year when demand is expected to pick up further," Nasser said, adding, "Unfortunately, there is not enough investment in the sector to increase supplies and maintain that spare capacity."

Biden administration vaccine-based travel rules that took effect Nov. 8 will bring the U.S. more in line with the European Union, boosting demand for transatlantic flights.

The additional traffic between the United State and Europe will likely add more than 250,000 bpd of oil demand, thanks to less restrictions on global vaccinated travelers, Bloomberg Intelligence analyst Fernando Valle said.

Some airlines, including Lufthansa Group, Air France-KLM, Southwest Airlines Co. and Alaska Air Group Inc. are beginning to react to higher fuel prices by hedging, despite large hedging losses sustained by the industry in 2020, according to a Nov. 5 Bloomberg report.

Some airlines, including Lufthansa Group, Air France-KLM, Southwest Airlines Co. and Alaska Air Group Inc. are beginning to react to higher fuel prices by hedging, despite large hedging losses sustained by the industry in 2020, according to a Nov. 5 Bloomberg report.

—STEVE SUTHERLIN

Contact Steve Sutherlin at ssutherlin@petroleumnews.com