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page 4 EIA notes increasing demand, slow ramp up in global oil production

Badami steady; price bumps ahead; decarbonizing O&G with digital

ON OCT. 7, STEPHEN RATCLIFF, president of Glacier Oil and Gas, told Petroleum News that progress at Badami is "steady," in terms of the company's Badami team doing a good job maintaining output.

Operated by Savant Alaska, a Glacier company, the eastern North Slope Badami field averaged 1,065 barrels of oil per day in August.

Production in the warmer months on the North Slope is normally lower for all fields. For example, Badami averaged 1,466 bpd in February, down 4.7%, 72 bpd, from a January average of 1,538 but up 8% from a February 2020 average of 1,357 bpd.

see **INSIDER** *page 6*

RRC continues to move towards filing RCA certificate application

The Railbelt Reliability Council is continuing to move towards filing an application to the Regulatory Commission of Alaska for a certificate as the electric reliability organization for the Alaska Railbelt electrical system, Julie Estey, chair of the RRC implementation committee, told a public meeting of the RCA on Oct. 13.

The RRC anticipates bringing a more unified approach to the oversight and management of the Railbelt system by maintaining and mandating reliability standards for the high voltage electrical system; administering rules for open access to the transmission grid; conducting Railbelt-wide system planning; and investigating ways to share costs across the grid and to reduce

see **RRC PROGRESS** *page 8*

Amaroq focuses on increasing gas production from Nicolai Creek unit

Coming

November 2021

Amaroq Resources LLC, operator of the Nicolai Creek unit on the west side of Cook Inlet, is working to increase natural gas production from the field, one of the inlet's smaller gas producers, while hoping for upside potential including the possibility of deeper oil at the field.

Amaroq, a small, privately funded company, is also fighting the Alaska Oil and Gas Conservation Commission's new bonding requirements in court.

Nicolai Creek natural gas is the company's only production. Amaroq filed a 47th plan of development for Nicolai Creek in

see **PRODUCERS PREVIEW** *page 8*

Playing with Alberta money: after C$497B, Quebec exits investments

It's best known as The Caisse, a shortened version of the long-winded French title for Quebec's institutional investor manager of several public pension plans covering a population of 8.2 million.

The Caisse has accumulated a portfolio worth about C$390 billion, making it Canada's second largest pension fund, and has set aside an C$11 billion fund to invest in new projects to tackle emissions from carbon-heavy industries such as cement and steel makers, while selling its remaining shares in Canadian and international oil producers.

At first glance that doesn't seem like an unreasonable strategy in these days of the global attacks on fossil fuel producers.

But try selling that line to Albertans, who have contributed

see **ALBERTA DOLLARS** *page 7*

FINANCE & ECONOMY

ANS cracks $83 mark

Cold weather expectations trump demand fears; gas and oil supplies tight

By STEVE SUTHERLIN

Petroleum News

The price of Alaska North Slope crude budged upward 10 cents to close at $83.71 per barrel Oct. 13. West Texas Intermediate fell 20 cents to close at $80.44, and Brent dropped 24 cents to close at $83.18.

The indexes are trading now at levels not seen since 2014.

The mixed, miniscule price action on the day occurred as demand fears due to the virulent delta variant of COVID-19 were balanced by expectations of a frigid Northern Hemisphere winter.

Meanwhile, high natural gas prices spur increased use of oil for electric generation and heating. Oil supply remains tight.

The Organization of the Petroleum Exporting Countries may have helped to cool price action on Oct. 13, with a new more pessimistic outlook for 2021 prices contained in its October OPEC Monthly Oil Market Report.

Oct. 13 trading capped a five-day run higher for ANS which saw its closing price jump $2.53, a 3.1% gain from its $81.18 Oct. 6 close.

Brent crossed the line to a close above the $83

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EXPLORATION & PRODUCTION

Shell targets Nanushuk

Will not operate in Alaska; wants one more year to find partner/operator

By KAY CASHMAN

Petroleum News

Shell Offshore Inc. is still not interested in operating in Alaska and continues to look for another company to drill its shallow water Beaufort Sea leases. When those leases are drilled, Shell wants to target the Nanushuk formation, not drill deeper into the Torok, as was mandated by the state of Alaska for the West Harrison Bay unit's first plan of exploration, which covered 2021.

In Shell's Oct. 6 filings proposing both an amendment to the West Harrison Bay unit's first plan of exploration and a second plan of exploration for 2022 (both posted Oct. 11), the company asked the Alaska Department of Natural Resources' Division of Oil and Gas for relief from having to drill down to the deeper Torok formation and for an extra year before Shell has to name a new unit operator.

That new unit operator, Shell told the division, will drill two exploration wells in the West Harrison Bay unit, the first in the winter drilling season of 2023-24 and the second in the winter of 2024-25.

In both cases, the new operator will complete the wells to penetrate and log the Nanushuk formation and, assuming the success of that well, a sidetrack or additional well to evaluate the Nanushuk formation will also be drilled.

Following the Oct. 6 filings, Shell spokeswoman Cindy Babski told Petroleum News in an email:

see **SHELL PLANS** *page 10*

PIPELINES & DOWNSTREAM

No pipeline wars letup

Canadian government joins Line 5 battle, Line 3 starts shipments, TC Energy sues

By GARY PARK

For Petroleum News

Line 3 and Line 5 — Enbridge's two troubled pipeline projects that have wrestled with opponents in the United States — have posted one significant gain but embarked on an uncertain path to protect rights to deliver crude bitumen into and through the U.S, Midwest.

At the same time, rival TC Energy has launched a US$15 billion claim against the U.S. government to cover its losses from President Joe Biden's decision to scuttle the Keystone XL.

On the upside, Enbridge said its replacement of an aging Line 3 started shipments on Oct. 1 by almost doubling capacity to 760,000 barrels per day from 390,000 bpd, making it the first new transportation link since Enbridge's Alberta Clipper project was finished in 2015.

The US$8.2 billion project carries the crude from Edmonton to refineries in the U.S. Midwest, ending years of operating below capacity because of the existing line's age and corrosion.

Leo Golden, Enbridge's vice president of Line 3, said the project points to the future of oil and gas pipelines.

He said the challenges faced by new energy infrastructure is reflected in Line 3 — a view echoed by Phillip Wallace, business representative for Pipeliners Union 798.

"The maintenance industry is our future. It's the

see **PIPELINES WARS** *page 9*

● LAND & LEASING

Lease rent reduced for Great Bear Pantheon

By KAY CASHMAN

Petroleum News

On Oct. 6, Alaska's Division of Oil and Gas approved Great Bear Pantheon's Sept. 7 request for a rental reduction on four state leases in the central North Slope's Talitha unit, which GBC operates.

The leases — ADL 392786, 392787, 392788 and 392789 — are the most recent acquired for the unit, having been won in the state's North Slope areawide lease sale in 2014. All four have a Dec. 1, 2015, effective date and a term of 10 years.

TOM STOKES

The division agreed to reduce the rent from $250 per acre to $10 an acre for the last three years, which is what GBP's working interest owners paid per acre for the first seven years of the lease term.

The four leases consist of 5,701 contiguous acres approximately 30 miles southwest of Prudhoe Bay between the Kuparuk River and the Dalton Highway.

The rental reduction application was submitted by GBP's Chief Commercial Officer Patrick Galvin on behalf of the working interest owners in the leases, which include Great Bear Petroleum Ventures II and Borealis Alaska.

Per the terms of the Nov. 12, 2020, Talitha unit formation decision and unit agreement, GBP had to drill one well within the initial two years, or two wells within the initial four years of the unit. (Wells had to be drilled to the base of the Kuparuk, or its equivalent, as seen at 10,375 feet measured depth in the Pipeline State No.1 well drilled by ARCO in 1988.)

In support of the application, GBP submitted work completed and confidential expenditure information associated with exploring and developing the leases.

Work performed

Although the amount of money spent for the work done on or near the four leases in the Talitha unit is confidential and was only shared with division officials, following is a list of the work from GBP's rental reduction application:

PATRICK GALVIN

- 2013 3D seismic survey covering lease area (the four leases are 1/48th of entire area of the seismic shoot), data collected was submitted to the division.
- August 2013 to present, analysis of Pipeline State No.1 well and 3D seismic, data submitted to the division.
- Talitha A well completed April 25 on Talitha unit acreage directly adjacent to the four leases, multiple zones covering the four leases, data submitted to the division.

The leases agreements provide the possibility of rental reduction if the division director — currently Tom Stokes — determines, upon request, that the lessee has exercised reasonable diligence in exploring and develop-

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● EXPLORATION & PRODUCTION

Major gas sale remains Pt Thomson focus

ExxonMobil tells state in 2-year development plan it continues to work with Alaska Gas Development Corp., Qilak LNG on projects

By KRISTEN NELSON
Petroleum News

Point Thomson unit operator ExxonMobil Alaska Production has submitted a two-year plan of development to the Alaska Division of Oil and Gas with continued focus on condensate production and providing information as needed for major gas sales projects.

ExxonMobil and Hilcorp North Slope are the major working interest owners at Point Thomson.

ExxonMobil told the division there were two changes in PTU ownership interests during the 2020-21 two-year POD: ConocoPhillips Alaska's interest in the PTU was transferred to BP Exploration (Alaska) effective Nov. 1, 2019, and, effective June 30, 2020, Hilcorp Alaska acquired the shares of BPXA and the name of that entity was changed to Hilcorp North Slope.

The new POD, submitted Oct. 1, covers Jan. 1, 2022, through Dec. 31, 2023.

ExxonMobil said the POD provides a summary of operations and development work under the 2020-21 POD and plans for future development, including planning for a major gas sale. The proposal, the company said, is consistent with the Sept. 10, 2018, letter of agreement between the state and the PTU working interest owners (major WIOs then were ExxonMobil, BPXA and ConocoPhillips Alaska), and the March 29, 2012, settlement agreement between the state and the WIOs (major owners the same as in the 2018 letter of agreement).

The 2012 settlement agreement was the result of the state's insistence that ExxonMobil and the other WIOs develop Point Thomson — or give up the leases. Leaseholders had long demurred, citing lack of a means to transport production. As a result of the settlement, ExxonMobil built a sales oil pipeline, linking Point Thomson to a pipeline built by BP to take Badami oil to connect with North Slope lines taking oil to the trans-Alaska oil pipeline.

ExxonMobil said the primary resource at Point Thomson is "natural gas with entrained condensate, contained within high pressure sands of the Thomson reservoir," with the field primarily lying offshore under state water and land. There have been 22 wells drilled in and around the PTU since the early 1970s, the company said, with the Thomson reservoir representing some 25% of known and recoverable natural gas resources on the North Slope.

Initial production system

ExxonMobil said it constructed the initial production system, IPS, at Point Thomson in 2012-16. The IPS is a high pressure, 10,000 psi, gas cycling project, the company said, using "industry-first reciprocal injection compressors" with condensate delivered for sale.

Once condensate is removed from the gas, gas is compressed and injected back into the reservoir.

IPS infrastructure, wells and facilities were designed to cycle 200 million standard cubic feet of gas per day and deliver up to 10,000 barrels per day of condensate to the trans-Alaska pipeline through the Point Thomson Export Pipeline.

Three wells are active, two injectors on the Central Pad and a production well on the West Pad. There is also a class 1 disposal well used for produced water and grey water disposal, the company said.

For Jan. 1, 2020, through July 31, 2021, condensate production averaged 8,300 barrels per day, the company said, with a maximum monthly average of 9,600 bpd achieved in May 2020 and a total of 4.8 million barrels of condensate delivered to the trans-Alaska oil pipeline.

Gas production averaged 151.2 million standard cubic feet per day, with 147.2 million standard cubic feet per day reinjected and the remaining gas used as fuel gas in unit operations. In May 2020 a maximum monthly average production of 179.6 million standard cubic feet per day was achieved.

In earlier years at Point Thomson, where production began in April 2016, there were reliability issues related to the gas injection equipment.

In the 2020-21 POD ExxonMobil said Point Thomson had "experienced issues related to its gas injection equipment, which is based on leading edge technology designed to handle gas reinjection at the high pressures of the Point Thomson reservoir," and said the unit worked with the equipment manufacturer to identify potential reliability improvements and modifications. The unit "designed and procured a modified component for use in its gas injection system," with the first of the new components installed in July 2019 and remaining equipment ordered for installation during the 2020-21 POD period.

ExxonMobil also said the unit "is upgrading the lubrication systems and continuing to optimize operations and maintenance practices to further increase reliability and reduce downtime."

In its current POD, for 2022-23, ExxonMobil said the new components which were installed starting in 2019 "enabled significant reliability improvements in 2020 and 2021."

Major gas sales

ExxonMobil said in its 2022-23 POD that as described in the 2018 letter agreement, the preferred development at Point Thomson is as a major gas sales project, "such as the Alaska LNG Project or the Qilak LNG Project," and said the unit plans to continue evaluating "facility modifications and development activities necessary to support any viable MGS project."

The company said that as PTU operator it has engaged in confidential discussions with the Alaska Gasline Development Corp. on the Alaska LNG Project, "to share knowledge in support of AGDC's efforts to identify potentially viable commercial structures for the project and to identify further opportunities to improve the competitiveness of the project," has provided support for Federal Energy Regulatory Commission permitting for the project and AGDC cost reduction studies and continues evaluating "the technical feasibility of required PTU facility modifications, including study of a potential option under which Alaska LNG would initially construct a pipeline from PTU to Fairbanks."

ExxonMobil also said that as PTU operator it has engaged in confidential discussions with Qilak LNG "to discuss advancing mutual objectives under the Heads of Agreement signed by the parties in October 2019," received periodic updates on the status of the Qilak LNG project feasibility studies and provided technical support and "conducted evaluations of the technical feasibility of various development scenarios, including assessments of PTU facility modifications and upgrades that would be necessary to supply the PTU gas to the project."

ExxonMobil provided a list of long-range activities that would be required "to ensure continued alignment with either MGS project."

Point Thomson expansion planning, required under the 2012 settlement, was suspended under the September 2018 letter agreement.

The company said no additional wells are planned during the 2022-23 POD period.

Reservoir management, facilities

ExxonMobil said reservoir management to date has met expectations, with no indications of reduced reservoir connectivity or capacity. No enhanced oil recovery efforts are planned through 2023.

Central Pad processing facilities have achieved production greater than the 200 million standard cubic feet per day of cycled gas and 10,000 bpd of condensate, the company said, and gas injection compressors have demonstrated "the ability to operate at maximum design capacity based on facility performance rates."

The 2012 settlement agreement required a debottlenecking program after IPS project startup, the company said, and debottlenecking opportunities have been reviewed "with the assistance of an independent engineering contractor," evaluating "operating parameters such as separator pressures and hydraulic limits, but no significant debottlenecking opportunities were identified to increase capacity." ●

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RENT REDUCED

ing the acreage.

Although a rental reduction was granted on other Talitha leases, there had been no prior application for a reduction on the four leases, making the four leases eligible for rental reduction, the division said in its approval.

The agency also said work completed on the leases and adjacent acreage added to the working interest owners' understanding of prospective reservoir targets on the leases and adjacent acreage.

Based on the expenditures made and the work completed, the division granted the rental reduction, saying the applicant had "exercised reasonable diligence to explore and develop the four leases during their primary term." ●

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EXPLORATION & PRODUCTION

Baker Hughes rig count rises by 5 to 533

For the week ending Oct. 8, the Baker Hughes U.S. rotary drilling rig count was up by five rigs from the preceding week to 533, an increase of 264 from 269 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 Oct. 8 count includes 433 rigs targeting oil, up five from the previous week and up 240 from 193 a year ago, with 99 rigs targeting gas, unchanged from the previous week and up 26 from 73 a year ago, and one miscellaneous rig, unchanged from the previous week and down by two from a year ago.

Twenty-two of the rigs reported Oct. 8 were drilling directional wells, 483 were drilling horizontal wells and 28 were drilling vertical wells.

Texas (247) had the largest week-over-week gain, up by four.

West Virginia (10) was up by two rigs.

California (7) and Oklahoma (41) were each up by a single rig.

Louisiana (45), Ohio (11) and Pennsylvania (17) were each down by a single rig from the previous week.

Counts in all other states were unchanged, week over week: Alaska (5), Colorado (11), New Mexico (86), North Dakota (22), Utah (10) and Wyoming (18).

Baker Hughes shows Alaska with five rigs active Oct. 8, unchanged from the previous week and up three from a year ago, when the state's count stood at two.

The rig count in the Permian, the most active basin in the country, was up by three from the previous week at 266 and up by 136 from a count of 130 a year ago.

—KRISTEN NELSON

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● FINANCE & ECONOMY

EIA sees higher Brent, Henry Hub prices

Agency cites increasing demand, slow ramp up in production, in estimating Brent will average $81 in fourth quarter, $72 in 2022

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration released its October Short-Term Energy Outlook Oct. 13, with forecasts for both Brent crude oil spit prices and Henry Hub spot prices up from the agency's September forecasts.


STEVE NALLEY

"As we have moved beyond what we expect to be the deepest part of the pandemic-related economic downturn, growth in energy demand has generally outpaced growth in supply," said EIA Acting Administrator Steve Nalley. "These dynamics are raising energy prices around the world."

EIA said Brent spot oil prices averaged $74 per barrel in September, up $4 per barrel from August — and up $34 per barrel from September 2020. By early October, Brent spot prices had risen to more than $80 per barrel, the agency said.

Price increases have been driven by steady draws in global oil inventories over the past year, the agency said, and by the Oct. 4 announcement from the OPEC+ that current production targets would remain unchanged.

Brent expected to average $81 in fourth quarter

The average of more than $80 per barrel for Brent oil prices so far in October is nearly a seven-year high, Nalley said, with the reduction in U.S. oil production following Hurricane Ida attributing to the price level.

EIA said its higher forecast for Brent, up $10 per barrel from its September forecast, reflects "much tighter oil markets during this period than we previously expected," with global oil inventories in the fourth quarter of this year and the first quarter of 2022 now expected to decline at an average of 500,000 barrels per day, compared with a forecast of mostly unchanged inventories in the agency's September forecast.

The Henry Hub spot natural gas price is expected to average $5.80 per million British thermal units in the fourth quarter, up $1.80 from last month's forecast, the agency said, with natural gas prices now expected to remain elevated through the first quarter of next year, and to average $4.01 per million Btu in the first quarter, up 4 cents from the September forecast.

Natural gas

"Increased natural gas demand in Europe and Asia is supporting record U.S. LNG exports to those regions," Nalley said. He said low inventories, both in the U.S. and in Europe make the agency's price forecasts "very uncertain, because a severe cold snap could lead to significant price effects."

U.S. liquefied natural gas exports are estimated to have averaged 9.3 billion cubic feet per day in September, EIA said, down 4% from August, but still a record for September since LNG exports began from the Lower 48 in February 2016.

The September exports were weather limited, with suspension of piloting services for several days at Sabine Pass, Cameron and Corpus Christi.

EIA expects LNG exports to average 9.1 bcf per day in October and increase as Cove Point LNG terminal completes its annual maintenance in mid-October. Exports are forecast to average 10.7 bcf per day through the winter "as global natural gas demand remains high and several new export trains — the sixth train at Sabine Pass LNG and the first trains at the new LNG export facility Calcasieu Pass LNG — enter service," the agency said.

U.S. dry natural gas production is estimated to have averaged 93.3 bcf per day in the third quarter, up from 91.6 bcf per day in the first half, with production expected to rise to an average of 94 bcf per day during the winter and average 96.4 bcf per day next year, "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.

US crude production

"We expect U.S. crude oil production to ramp up in 2022 as tight oil production rises, which should help moderate prices from this level next year," Nalley said.

EIA said U.S. crude oil production averaged 11.3 million barrels per day in July, the last month for which historic data are available.

The agency said domestic production is estimated to have fallen to 10.6 million bpd in September because of disruptions from Hurricane Ida. Production is forecast to be 11 million bpd in October and rise to 11.3 million bpd in December, with 2021 production expected to average 11 million bpd, and 2022 to average 11.7 million bpd "as tight oil production rises in the United States. Growth will come as a result of operators increasing rig counts, which we expect will offset production decline rates," EIA said.

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● PIPELINES & DOWNSTREAM

Legal fight over CA spill likely lengthy

By BRIAN MELLEY

Associated Press

It took little more than 48 hours from the moment a major oil spill was discovered off Southern California until the first lawsuit was filed against the Houston company that owns and operates the ruptured pipeline.

Finding the cause, who is to blame and if they will be held accountable will take much longer.

Several federal and state agencies are investigating in parallel as they seek the cause of the pipe rupture, how quickly pipeline operators responded and determine whether criminal charges are warranted.

Coast Guard Capt. Jason Neubauer said investigators are trying to find which ship among thousands of possibilities may have snagged the pipeline with its anchor in the past year, possibly during rough seas and high winds in January.

"We are not ruling out anybody at this time," Neubauer said.

First reported Oct. 1

A possible leak off the Orange County coast south of Los Angeles was first reported Oct. 1. The spill was confirmed the next morning, and crude came ashore on Huntington Beach and then spread south to other beaches. Much of the coastline nearby was shut down more than a week, crippling businesses that cater to beachgoers and boaters.

The Coast Guard has estimated between about 25,000 gallons and 132,000 gallons spilled.

It could take a long time for investigators to comb through marine tracking data to see which ships passed over and anchored near the Amplify Energy pipeline running from platform Elly to the Long Beach port.

Investigations by federal prosecutors, the Coast Guard and several other federal agencies, including the National Transportation Safety Board, could lead to criminal charges, civil penalties and new laws or regulations.

"Criminal charges — when they're warranted — you absolutely want to go after for all the reasons that you pursue criminal charges: accountability, deterrence, punishment," said attorney Rohan Virginkar, a former assistant U.S. attorney who helped prosecute BP for the Deepwater Horizon oil spill in the Gulf of Mexico in 2010. "But really in these environmental cases, it's about finding somebody who's going to pay for the cleanup."

Two vessels already boarded

Coast Guard investigators already have boarded two vessels and plan to track down others, many from overseas, Neubauer said. They will inspect anchors for damage and review all logs kept by the captain, deck officers and engineers, and the voyage data recorder — the equivalent of the so-called black box on airplanes. They will also interview crew.

Under some environmental laws, prosecutors only have to show negligence to win a conviction, Virginkar said. That could lead to a charge against a shipping company for anchoring outside an assigned anchorage or too close to a pipeline marked on nautical charts.

The accident occurred where huge cargo ships anchor waiting to unload at the Los Angeles-Long Beach port complex — the nation's largest.

Other investigators, including federal pipeline regulators, will focus on Amplify Energy, which owns the three offshore oil platforms and the pipeline.

They will review pipeline inspections for evidence of corrosion that might show it was being operated negligently and seek any information that records were falsified, which is what they found in the BP case, said attorney William Carter, a former federal environmental crimes prosecutor. A forensic analysis will be performed after the cracked is retrieved from 100 feet of water.

The Amplify pipeline was required to have thorough inside and outside checks on alternating years. The most recent showed no issues requiring repairs, according to federal documents.

Prosecutors will also scrutinize control

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EIA OUTLOOK

U.S. crude oil stocks have decreased in each of the last six months, down 81 million barrels, 16%, since March, EIA said, "the largest six-month withdrawal on record in our crude oil data for all inventories outside of the Strategic Petroleum Reserve, which go back to 1973."

Low production has been a major factor in the crude stock draws, with increases in demand outpacing production.

Average U.S. crude oil production from January through August was 11 million bpd, EIA said, compared to 12 million bpd in the same period in 2019 and production dropped to 10.6 million bpd in September "because of lower U.S. offshore oil production in the Gulf of Mexico after Hurricane Ida."

Slow global production

EIA said global liquid fuels production has also risen more slowly than demand this year, with production up by 2.7 million bpd, 3%, from January to September, but global consumption increasing by 6.3 million bpd, 7%, during this same period.

And OPEC+ reaffirmed a previously agreed on increase of 400,000 bpd in November.

EIA said it now expects global oil inventories in the fourth quarter of this year and the first quarter of next year to fall at a faster rate than it previously expected, "which largely reflects lower global oil supply during this period across a range of producers."

The agency said it has also raised its expectation for global oil demand this winter and expects falling global inventories to keep Brent near $80 per barrel this winter, averaging $81 per barrel in the fourth quarter of this year and $78 per barrel in the first quarter of 2022.

West Texas Intermediate prices are expected to average $78 per barrel in the fourth quarter. ●

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EXPLORATION & PRODUCTION

Glacier restarts Redoubt unit, WMRU next

Glacier Oil & Gas put the Cook Inlet Redoubt unit back online Sept. 28, with current output at 1,200 barrels a day, company President Stephen Ratcliff told Petroleum News Oct. 7. The field, which is offshore in Cook Inlet north of Kalgin Island, has been shut down since May 2020.

"Production is fully restarted; all producers and injectors are back online," Ratcliff said.

"All ESPs (electric submersible pumps) came back online. We're still going through the ramp-up process, and cleaning up each well," he said, noting that the 1,200 barrels a day output "met our expectations."

Ratcliff praised the company's Cook Inlet team members for their dedication and skill in bringing Redoubt back online.

"We've had a lot of good support from the agencies and our people," Ratcliff added.

"Our Cook Inlet and Badami teams are doing a good job. We're focused on the things we can control, and they done a great job on those things," he said.

In working to rebuild the company, Ratcliff said, "We've come a long way in the last 12 to 18 months. Our hearts are in it. … Our focus is on being a good Cook Inlet and North Slope producer."

Redoubt, operated by Cook Inlet Energy, a Glacier company, averaged 1,303 bpd in February 2020, but in March of that year output had fallen to 904 bpd. It recovered in April, averaging 1,676 bpd, which was a 36.1% increase from an April 2019 average of 1,231 bpd.

Forest Oil Corp. began oil production at the Redoubt Shoal field on Dec. 9, 2002.

Cook Inlet Energy is currently operating Redoubt under an extended 20th plan of development. It must submit its proposed 21st POD to the division no later than 30 days after the resumption of production.

Ratcliff also said Glacier would "hopefully have the Cook Inlet West McArthur River unit back online sometime in November."

The company expects WMRU production will give Glacier's Cook Inlet oil output a "300-500 bpd uptick," Ratcliff said.

—KAY CASHMAN

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INSIDER

For BP, the field's original operator, by August 2007 production had fallen to 876 barrels a day.

BP brought the Badami oil field into production in August 1998. It was first in a "string of pearls," or new pipelines between undeveloped oil discoveries on Alaska's North Slope, to make their way east from Pump Station 1 of the trans-Alaska oil pipeline at Prudhoe Bay to the border of the ANWR 1002 area, a total of about 70 miles as a goose flies.


STEPHEN RATCLIFF

From nearly the beginning, the Badami sands reservoir's complex geology — compartmentalized into multiple, discrete sand bodies — rendered the Badami unit challenging to produce.

Starting early in the field's life, oil output declined so severely that BP suspended production on several occasions, with one suspension lasting for two years. Field suspension allowed the Badami sands reservoir pressure to recharge, as subsurface oil slowly migrated between the various sand units.

A disappointment for BP, which had built a 38,500 barrel-a-day capacity Badami processing plant, in mid-2008, BP brought in Savant as a partner and operator, eventually selling out to the small independent.

While Savant has been much more successful with oil production from the Badami sands with only one multi-month shutdown (due to the 2020 oil price crash), the company has also looked outside the Badami participating area for new sources of oil.

Savant's first discovery was in early 2010 with the B1-38 well, followed by the Starfish prospect's B1-07 well which was drilled after Savant became part of Glacier. Both the discoveries were in the shallow Cretaceous Killian sands, a Brookian interval, although B1-38 in the Red Wolf prospect also had oil in the deeper Kekiktuk formation that contains the oil reservoir for the Endicott field to the west.

As a result of these successes and well work, Savant has been able to keep Badami producing.

For several months Glacier had Badami up for sale. But on Aug. 23, Ratcliff told Petroleum News that the oil field was no longer on the market.

More price shocks coming

WORLD ENERGY MARKETS will face more turbulence and price increases this decade due to inadequate investments, the International Energy Agency said in its annual World Energy Outlook released in mid-October.

A decrease in oil and gas investment in recent years due to more interest in alternative energy to address climate change is part of the reason.

But instead of demanding oil and gas companies reduce production, IEA says the solution is to dramatically boost alternative energy spending.

To reach net-zero emissions by 2050, IEA said that alternative energy investment must more than triple over the next decade to nearly $4 trillion annually by 2030.

Without this occurring, the agency said volatile energy prices and shortages could become the norm through the decade.

"At the moment, however, every data point showing the speed of change in energy can be countered by another showing the stubbornness of the status quo. The rapid but uneven economic recovery from last year's Covid-induced recession is putting major strains on parts of today's energy system, sparking sharp price rises in natural gas, coal and electricity markets. For all the advances being made by renewables and electric mobility, 2021 is seeing a large rebound in coal and oil use," IEA said in its report abstract.

Decarbonizing oil and gas with digital

WORLD OIL'S SEPTEMBER issue: "For many years, digital innovation has played an important role in improving efficiency and enabling returns-focused performance for this crucial phase of the well life cycle. Today, however, digital plays an equally important role in reducing CO2 emissions as climate change impacts continue to mount."

This article explains some of the unique challenges oil and gas operators are facing and how digital is helping to solve them in the drilling and well construction domain.

The story begins with the following: "As the world emerges from the pandemic, oil demand that was slashed by coronavirus-related lockdowns and travel restrictions is once again on the uptick.

"While demand forecasts are being updated continuously to account for the dynamic situation with the virus, current indicators point toward oil reaching pre-pandemic levels by the end of 2022, followed by a period of continued growth.

"This is setting the stage for a multi-year, demand-led recovery for the industry."

Check it out at: https://www.worldoil.com.

—Oil Patch Insider is compiled by Kay Cashman

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ALBERTA DOLLARS

C$630 billion to level out the national wealth since a national equalization plan was introduced in 1960 — C$497 billion of which was pumped into the Quebec treasury.

Reallocation of its financial windfall — based mostly on its returns from natural resources — has meant Alberta is the only one of 10 provinces never to have collected from the equalization program, even in recent years as its budget deficits have soared.

According to Ted Morton, a former Alberta finance minister, the real source of Alberta's downward fiscal spiral is the formula for equalization that has seen C$90 billion drained out of Alberta's treasury since Justin Trudeau was elected prime minister in 2015. "The problem is that our tax dollars don't stay in Alberta," he wrote in the Calgary Herald earlier this year.

But Morton sees hope in a referendum Alberta Premier Jason Kenney has included as part of municipal elections on Oct. 18, which will determine whether Albertans want its government to negotiate removal of equalization from the Canadian Constitution — an unlikely event no matter what results from the voting.

Acceleration to green investments

For now, though, The Caisse has decided to accelerate its transition to green energy investments by unloading some of its C$4 billion in shares of oil producers after spending the past few years applying climate risk calculations to its investment decisions.

But the fund will for now retain interests in Canada's largest oil producer Suncor Energy, Sweden's Lundin Energy and U.S.-based Occidental Petroleum and Pioneer Natural Resources.

Reallocation of its financial windfall — based mostly on its returns from natural resources — has meant Alberta is the only one of 10 provinces never to have collected from the equalization program, even in recent years as its budget deficits have soared.

The Caisse will also keep its positions in oil and gas pipelines, including U.S.-based Colonial Pipeline, as part of its infrastructure portfolio, saying they remain necessary as the world gradually switches over to greener energy sources.

The fund said it has exceeded targets set in 2017 to bulk up on green assets and reduce carbon intensity. Now it aims to have C$54 billion in green assets by 2025 and achieve a 60% cut in carbon intensity by 2030. Today, it has C$36 billion in green assets, including renewable energy and sustainable buildings.

Ignoring what companies are doing

Tim McMillan, president of the Canadian Association of Petroleum Producers, said The Caisse decision ignores investments companies across the petroleum sector are making to lower their carbon intensity and benefits producing countries with less stringent environmental regulations as demand for oil and gas surges following the pandemic.

"My first thought was that it's irresponsible, first to those that they hold the investments for and for the environmental outcomes that they are purporting to do it for," he said.

A spokeswoman for Alberta Energy Minister Sonya Savage noted that Quebec is the second-largest market for refined petroleum products and said any decisions to divest from the oil and gas industry are "short-sighted and disconnected from reality."

"Oil and gas will remain an integral part of the global energy supply mix for the next several decades and that energy should come from Alberta," she said.

The Caisse Chief Executive Officer Charles Edmond did not rule out new investments in energy projects so long as they are specifically aimed at the transition to net zero emissions.

"We are trying to send the right signal with our capital that we're serious about taking that pivot," he said.

Distrust in Quebec

For now Alberta sees little reason to believe any pro-industry comments from Quebec since that province effectively scuttled a plan by TC Energy to build the Energy East pipeline plan across Quebec on its way to Canada's largest refinery and a crude export terminal in New Brunswick, ending hopes for a new outlet for 1.1 million barrels per day of crude bitumen from the Alberta oil sands.

Not even Utica Resources, a small Quebec-based oil and gas player, has any trust in the Quebec government.

It has filed a lawsuit against the Quebec government's decision to reject the company's application to develop the first major commercial play on Quebec territory after decades of flirting with the industry.

Utica alleges the province acted illegally and with political motives in rejecting its bid to obtain an exploratory drilling license near the town of Gaspe by establishing a minimum distance of 1 kilometer between drilling sites and water sources and acting "on the fringes" of existing laws.

Utica said the government has "annihilated any possibility of exploring, producing and developing hydrocarbon resources."

The company is seeking an unspecified amount of financial compensation that industry sources said could range from C$500 million to C$3 billion, depending on whether potential lost revenues are factored in.

That dispute comes only two months after the Quebec government rejected GNL Quebec's C$14 billion LNG export project because it was "uncertain" that the venture would reduce greenhouse gas emissions.

—GARY PARK

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SPILL FIGHT

room data to see if there were pipeline pressure drops that would have indicated a possible leak and what was done to respond, Carter said.

The company could be prosecuted if it realized there was a leak and did not quickly call state and federal hotlines to alert the Coast Guard, fish and wildlife officials and multiple other agencies that respond to spills, Carter said.

Prosecution for an untimely response is fairly common in spills, he said.

"The elements necessary for that violation are: I knew there was a release, and I didn't immediately report it _ regardless of the cause," Carter said. "I mean, it could have been lightning or an earthquake did it and you knew it, and you didn't report it — a timely fashion."

Plains All American Pipeline was convicted for that crime for a breach in a pipe on land that sent tens of thousands of gallons of crude pouring onto a Santa Barbara beach and into the ocean in 2015.

In the Amplify pipeline leak, federal regulators said a low-pressure alarm at 2:30 a.m. Oct. 2 alerted control room operators on platform Elly to a possible leak. The Pipeline and Hazardous Materials Safety Administration said the line wasn't shut down until 6:01 a.m. and the Coast Guard wasn't notified until 9:07 a.m.

Amplify CEO Martyn Willsher has refused to answer questions about the reported pressure drop, including the fact that the first report to authorities made on behalf of the company listed the incident at 2:30 a.m. He has insisted the company didn't know of the spill until a company inspection boat saw the sheen at 8:09 a.m.

Carter said lawyers probably told Willsher not to discuss the timeline because he could incriminate himself.

If charged with failure to report the spill quickly, the company could also face charges for allowing oil to harm endangered species and other wildlife that might have been saved by a more prompt response.

Federal prosecutors have five years to bring felony charges. Carter said they would likely wait until they know the cost of the damage to demand restitution.

Federal penalties for failing to notify authorities can be $500,000 or it could be as much as double the total damage. State penalties could run up to $10 per gallon spilled that wasn't recovered.

Regardless of whether a ship is ultimately found to be the cause of the spill, the Oil Pollution Act of 1990 requires whoever spills the oil to pay for the cleanup, said attorney James Mercante, a maritime lawyer. Amplify, however, can later seek to recover its losses from other liable parties.

Mercante said the law was passed in the wake of the Exxon Valdez tanker spill in Alaska in 1989 to speed the cleanup without finger-pointing.

"The spirit and purpose is to get the oil cleaned up and then fight it out," Mercante said. "It will take years and years and years to be resolved."

So far, two proposed class-action lawsuits have been filed on behalf of a disc jockey who runs beachfront events in Huntington Beach and a surf school that operates in the city known as "Surf City USA."

Those cases will rely heavily on government investigations and will take years to play out. ●

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PRODUCERS PREVIEW

September 2020 with the Alaska Division of Oil and Gas and on Oct. 11, 2021, the company filed a progress report on that POD, reviewing work at the unit and reporting on the status of its legal challenge to AOGCC's new bonding requirements.

A 48th POD had not been filed when this story went to press.

In its November 2020 approval of the 47th POD, the division said the field first produced in 1968, with many years between production.

AOGCC data show regular production at the field from 1968 through 1977, with production starting up again in 2001.

SCOTT PFOFF

Aurora Gas succeeded Union Oil of California as operator in 2000, the division said, and after Aurora Gas filed for reorganization in federal bankruptcy court, Aurora Exploration (which later changed its name to Amaroq Resources) acquired Nicolai Creek out of bankruptcy effective Jan. 1, 2018.

In the 47th POD, filed Sept. 28, 2020, Amaroq President G. Scott Pfoff said production from the unit totaled 92,881 thousand cubic feet, mcf, for the 12 months from Sept. 1, 2019, through Aug. 31, 2020. This was a decrease from the same period in the previous year, when the field produced 145,391 mcf of gas, although water production 2,966 barrels

AOGCC data show that from Sept. 1, 2020, to Aug. 31, 2021, the field produced 133,067 mcf of gas, up 43% from the previous year.

But another volume grew faster: water produced at the field along with the gas totaled 297 barrels from Sept. 1, 2019, through Aug. 31, 2020, but the most recent year, September 2020 through August 2021, saw 8,756 barrels of water produced, an increase of 2,848%.

Comparing natural gas production for the most recent month, August 2021, for which AOGCC data were available when this story when to press, the field averaged 530 mcf per day, up 33.7% from an August 2020 average of 397 mcf per day.

Disposal well

Nicolai Creek formerly had access to a nearby disposal well for water which was produced with natural gas, but that well was plugged and abandoned.

In 2019, Amaroq applied to AOGCC for underground disposal of Class II oil field waste fluids into the Nicolai Creek unit 1B well, which would allow the company to bring the Nicolai Creek unit No. 10 well, considered to have the most production potential, back online.

Following commission approval, in the spring and early summer of 2020 Amaroq converted the 1B well for oil field waste fluids disposal.

In its October 2021 progress report to the division, the company said it used a portable rental pump to inject produced water until completion of permanent injection facilities in the fourth quarter of 2020. Freezing temperatures and poor road conditions prevented permanent startup of the injection well until the second quarter of 2021.

Injection rates are some 250 barrels per day, Amaroq reported in October 2021.

Nicolai Creek unit No. 10 well

AOGCC data show 2020 production from three wells, Nicolai Creek unit Nos. 2, 9 and 11; in August 2021, production was from two wells, Nicolai Creek unit Nos. 9 and 10.

In the 47th POD Amaroq reported the Nicolai Creek unit No. 10 well remained shut-in until the 1B disposal well could be completed to handle water disposal. The company said it would continue to evaluate the economics of a gravel pack and/or rig workover at NCU 10, "which would facilitate production at much higher rates."

In 2019 filings related to its application for disposal at the NCU 1B well, Amaroq said it estimated that proved reserves at Nicolai Creek were on the order of 1.8 billion cubic feet, with some 1 bcf of those proved reserves allocated to the NCU 10, which the company said was expected to produce 100 to 200 barrels per day of water when on production.

Pfoff said in the Oct. 11, 2021, progress report that the company wasn't able to put the NCU 10 well into production until May 2021. "The well has produced sporadically since and is producing quantities of water higher than originally anticipated," he said.

AOGCC data show NCU 10 produced for a single day in May, 124 mcf. In July it produced 1,184 mcf of gas for the month and 1,552 barrels of water; in August, gas production was 1,924 mcf and water production 7,013 barrels.

The highest historic rate for the NCU 10 reported in AOGCC data was in March 2012, when it produced 99,167 mcf for the month.

Field purchase and upside potential

Pfoff discussed the acquisition of Nicolai Creek in a Feb. 18, 2020, AOGCC public hearing on the company's request for reconsideration of bonding requirements.

He said the field was purchased out of bankruptcy for $100,000 cash and the owners have since put half a million into well workover expenses and about $100,000 into needed compressor repairs and overhaul.

The owners see significant upside potential at the unit, both in proved, developed gas reserves and in probable reserves.

Additional conventional development includes oil prospects under the current gas producing zones and unconventional coalbed methane potential.

Amaroq Resources is owned 66.66% by Trading Bay Oil & Gas LLC and 33.34% by Aurora Power Resources Inc. Trading Bay is 100% owned by Paul Craig; Aurora Power Resources is 85% owned by G. Scott Pfoff and 7.5% by David Boelens.

The bonding issue

Amaroq's dispute with AOGCC over the commission's new bonding requirements is now in Superior Court.

In its October 2021 progress report Amaroq said it appealed AOGCC's final order on its reconsideration request of the required bonding amount to Superior Court on Dec. 9, 2020, and as of June 1, 2021, the company said, it had filed its initial brief and awaited AOGCC's response.

The commission's original bonding requirement was $2.4 million for the field's six wells, less the $200,000 bonding Amaroq already had in place with AOGCC. The commission reduced the amount of additional bonding to $700,000 based on costs for plugging and abandoning wells in the area.

Amaroq is contesting that amount, which the company says is more than double estimates it has received to P&A the wells. The company also says AOGCC is ignoring a DR&R — dismantle, remove and restore — agreement Amaroq has with the Department of Natural Resources. Amaroq says the AOGCC bonding requirement duplicates its DR&R agreement with DNR. That agreement includes P&A of the wells, the company has said, while the commission has said the DR&R agreement does not include a specific amount dedicated to P&A of the wells.

—KRISTEN NELSON

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RRC PROGRESS

power generation fuel costs for consumers. In 2020 the state Legislature passed Senate Bill 123, legislation that enables the RCA to regulate EROs in Alaska. And on June 29 of this year the commission issued regulations for the implementation of SB 123, setting the legal rules under which EROs can be certified and regulated. However, the new regulations still need to be approved by the Department of Law and the lieutenant governor before they can go into effect.

Estey said that the RRC implementation committee has hired additional staff to help ensure that the organization's RCA certificate application meets the regulatory requirements, and to provide expertise in electrical system standards, tariffs and integrated resource planning.

A first of its kind

The RRC application, the first application of its type, will set a precedent for ERO certificate applications, Estey commented. Given this situation and the resultant lack of a track record for this type of application in Alaska, the implementation committee is documenting questions to put to the RCA prior to the submittal of the certificate application. And once the regulations have been finalized through lieutenant governor approval, the committee plans a work session, open to the public and other potential certificate applicants, to discuss the questions that the RRC has raised and the essential elements of the application, Estey said. Uncertainty in interpreting the ERO regulations is presenting challenges in preparing the RRC certificate application, she commented.

The board structure

One of the thorniest issues revolves around the question of ensuring an appropriately balanced structure for the RRC governance board, so that all significant stakeholders are appropriately represented in setting RRC policies. In its regulations the RCA has included a lengthy definition of what the agency would consider to constitute an appropriately balanced board structure. Stakeholders in the electrical system include, for example, electricity consumers, the electric utilities and independent power producers.

To comply with the regulatory definition of a balanced board, during the summer the RRC announced that it was going to add a representative from a large commercial electricity consumer to its board membership. Estey said that the implementation committee has since selected a representative from the Alaska Native Tribal Health Consortium to fill that seat. Other voting board members would consist of representatives from the five Railbelt electric utilities, Doyon Utilities, the Alaska Energy Authority, Cook Inlet Region Inc. (operator of the Fire Island wind farm), Alaska Environmental Power (operator of Delta Wind), and two non-affiliated members, one of which is Renewable Energy Alaska Project. The RCA and the State Agency for Regulatory Affairs and Public Advocacy would each have a non-voting seat on the board.

—ALAN BAILEY

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PIPELINE WARS

lifeline of the (pipeline sector). Line 3 was the big boy that needed replacing badly," Wallace said.

The finished project ensures Canadian producers of oil sands crude will have access to U.S. markets and global exports through shipping terminals on the U.S. Gulf Coast.

Line 5

Attention now turns to a bare-knuckles brawl between Michigan Governor Gretchen Whitmer and a formidable joint force of the Canadian, Ontario and Alberta governments, Alberta crude producers and Michigan customers who rely for their survival on crude by-products, notably propane.

The Canadian government has invoked its 1977 Transit Pipelines Treaty with the U.S. to trigger formal negotiations between the two countries over the fate of Line 5.

That in turn cranks up a dispute in which Biden has avoided playing a role, five months after his Energy Secretary Jennifer Granholm told reporters that the White House had no plans to get involved so long as there was a chance the courts could settle the matter.

Canada's Foreign Affairs Minister Marc Garneau said his government is "firmly committed to ensuring our energy and economic security."

"The Biden administration will not be able to duck this issue any longer," said Toronto international trade lawyer Lawrence Herman.

Gordon Giffin, a former U.S. ambassador to Canada now acting as legal counsel for the Canadian government, asked Janet Neff, the U.S. district judge presiding over the Enbridge-Michigan dispute, to suspend court proceedings while formal negotiations between Canada and the U.S. take place.

"It is neither necessary nor proper for this court, or any other domestic court, to make any determination that could

Attention now turns to a bare-knuckles brawl between Michigan Governor Gretchen Whitmer and a formidable joint force of the Canadian, Ontario and Alberta governments, Alberta crude producers and Michigan customers who rely for their survival on crude by-products, notably propane.

undermine, conflict or interfere with the obligations and processes established by the treaty," he wrote to Neff.

Treaty

The treaty is designed to ensure uninterrupted transmission of petroleum between the two countries.

It says the only justifications for impeding the flow are natural disasters or emergencies — and even then only temporarily.

Derek Burney, a former Canadian ambassador to Washington, said it was a "very sad commentary on the state of the (Canada-U.S.) relationship if we have to invoke a treaty in order to assert our rights."

But Whitmer takes every opportunity to stir the pot by referring to Canada as a "foreign power," ignoring decades of cross-border trade in oil and natural gas, especially at times when the U.S. was faced with OPEC embargoes.

The Coalition of Building Trades Unions, representing unions in Canada (notably Ontario and Quebec), Michigan and Ohio was formed in response to Michigan's notice of termination of Line 5's 1953 easement to cross the Straits of Mackinac in the Great Lakes over concerns about a potential spill.

Member unions of the coalition have estimated that shutting down Line 5 would endanger 3,600 jobs in Montreal's petrochemical industry, 4,900 jobs at Ontario's Sarnia refinery complex and 23,500 indirect jobs in the Sarnia area, 500 jobs at Ohio's Toledo refinery and the potential loss of another 1,000 jobs in northwest Ohio — all facilities that depend on crude carried by Line 5.

"We can't let this vital (pipeline) that we have relied on for nearly 70 years be shut down," said Steve Calywell, president of the Michigan Building and Construction Trades Council.

Pipelines bailing

But, just as they need all of the strong voices they can muster, Canada's leading pipelines have been bailing out of the lobbying organization they formed 28 years ago.

The Canadian Energy Pipeline Association has announced it will cease operations by Dec. 31, having seen three of its dozen member companies — TC Energy, Enbridge and Pembina Pipeline — quit the ranks since 2016.

CEPA President Chris Bloomer said it had become increasingly difficult to lobby for changes to government policy over the past decade, especially as fossil-fuel companies started pivoting to renewables or incorporating green technologies into their operations under pressure from investors.

The association at its peak spoke for companies that transported on an annual basis 4.5 trillion cubic feet of natural gas and 1.3 billion barrels of crude oil, often more than half of those volumes destined for the U.S.

Bloomer said the "big guys represented a critical mass (for CEPA). When you have them you're speaking for the whole industry. When you lose that constituency, it's tough."

But that doesn't mean "this industry is throwing in the towel by any means," he said, suggesting companies want to tell their own stories when it comes to lowering carbon emissions or incorporating more renewables into their energy mix. ●

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Petroleum news

Oil Patch Bits

Morgan City Oilfield Fishing Rodeo supports PETSM

As reported by HoumaTimes.com Oct. 6, the Morgan City Oilfield Fishing Rodeo is donating $10,000 to the petroleum engineering technology and safety management programs at Nicholls State University.

Dr. Milton Saidu said the program will use the money to purchase process safety management laboratory equipment and hazard analysis simulation modules.

Tanks-A-Lot, a deep-water container specialist, founded the fishing rodeo in 2013. The rodeo's goal is to promote a community spirit in the local oil and gas industry. This objective is achieved by contributing to notable, forward-thinking community organizations like Nicholls.

The fishing rodeo has donated more than $72,000 to the petroleum program at Nicholls since 2013. The money has been used to renovate and expand classrooms and improve technology. The donations have also helped build the state-of-the-art well control simulation lab.

"Nicholls has served our community for over half a century in providing quality education resulting in a higher quality of life for the people in our area," said Joey Cannata, operations manager at Tanks-A-Lot. "The MCOFR trusts that our contribution will positively impact the university and we are grateful for the opportunity to support the petroleum programs and the continued success of the university."

For more information on Nicholls Petroleum Programs, visit www.nicholls.edu/petsm/.

Companies involved in Alaska's oil and gas industry

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

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SHELL PLANS

"Shell continues to seek a company who will act as operator for the unit, located in state waters of the North Slope of Alaska. The unit leases were originally purchased in 2012. Shell has no intention of operating this unit and plans to fully divest out of the venture following exploration by the new operator. We have sold or relinquished all our frontier licenses in Alaska and have no plans for frontier exploration offshore Alaska."

Shell told the division that during the past year it has "worked diligently" to identify another company(ies) to acquire an interest in the West Harrison Bay unit's 18 leases, take-on the role of unit operator and share the exploration risk and cost associated with advancing the understanding of the resource potential of the shallow water Beaufort leases, evaluate the economic issues around any future development, and prepare a comprehensive plan of development based on the additional required geologic information" that will be gathered from the proposed well drilling and testing.

Made 'solid progress'

Shell said it "made solid progress" toward its objective of bringing in investment and a new operator prior to the Covid-19 pandemic and the resulting collapse in oil prices.

"While oil projects on the North Slope remain attractive from the standpoint of geologic potential, price and the fiscal assumptions that are expected to prevail in the coming decades, the challenges posed by the continuing economic uncertainty resulting from the Covid-19 pandemic have impacted Shell's ability to bring another company(ies) to this project in a number of ways," the company said.

"Covid-19 makes marketing the project more challenging as all meetings and negotiations have to be held virtually, and because the timing of execution of the project is uncertain due to logistical restrictions to operations, including surveying; and, until very recently, the low oil price suppresses the cashflow available to prospective investors for new projects and management appetite for new, higher risk exploration projects," Shell told the division.

2022 planned activities

In its second plan of exploration for the 81,000-acre West Harrison Bay unit, Shell committed to finish "additional required engineering and environmental studies necessary to support a future plan of development," as well as support exploration drilling by a new unit operator.

Specifically, Shell said during calendar year 2022, it will complete the following:

• Continue its work to identify outstanding data needs or issues of "particular relevance to state and federal regulatory agencies and establish a schedule and project plan" for addressing the same. Engage with relevant state and federal agencies to review the lease stipulations and mitigation measures applicable to future exploration activities at location and establish a framework for working cooperatively with the relevant regulatory agencies to resolve issues that might arise during future operations. Develop a schedule and project plan for completing outstanding data requirements.

• Complete a data gap and alternatives analysis to determine what additional studies are required to advance exploration activities in the unit. Assemble a comprehensive inventory of recently completed and relevant studies; summarize preliminary project planning and engineering of alternatives; and identify outstanding datasets to satisfy exploration drilling permitting requirements.

• Finalize commercial arrangements with another company(ies) to share the exploration risks and costs associated with the plan of exploration.

• Designate a new unit operator and initiate DNR's s regulatory review process required for approval of a new operator.

After evaluating the results of the well(s) completed during the winter 2023-24 and 2024-25 drilling seasons, Shell said that new unit operator would submit either a further plan of exploration for the West Harrison Bay unit or a plan of development no later than Dec. 31, 2025.

Early unit formation critical

On June 27, 2020, Shell said it submitted an application for formation of the West Harrison Bay unit, together with its proposed first plan of exploration.

While the primary term of the unit's leases ran through Nov. 30, 2022, Shell determined, "based on discussions with various companies it had approached regarding joining the venture and taking-on the status of operator," that "early formation of a unit encompassing its West Harrison Bay leases would greatly aid it in successfully completing a commercial agreement with a new unit operator."

In other words, formation of a unit gave Shell and a new operator enough time to execute the exploration drilling program that Shell's technical team had designed based on existing seismic data and well data in the region, and to further evaluate the acreage's resource potential.

Discussions advancing

Shell's proposed amendment to the approved first plan of exploration for 2021 would extend the date for Shell to finalize commercial arrangements with other prospective project participants and designate a new unit operator from Dec. 31, 2021, to Dec. 31, 2022.

Shell's efforts to secure additional project participants and designate a new operator for West Harrison Bay exploration over the last year were complicated by the continuing Covid-19 pandemic and general oil market uncertainty.

However, recently, market conditions have improved and Shell said its discussions with prospective project participants have progressed to the point where those potential participants are reviewing technical information in the unit's data room and "advancing their internal discussions around possible participation in the proposed exploration program."

Thus, Shell's reasons for wanting to extend the drilling of the exploration wells by one year each.

Torok possibility in future

As detailed and analyzed in the materials submitted in support of the formation of the Western Harrison Bay unit, Shell believes that, across the leases, the Nanushuk formation is the most prospective for commercial quantities of hydrocarbons.

The two-well exploration and delineation drilling program proposed in its initial exploration plan was specifically designed to test that target. However, in its approval the division added a condition that required the wells be drilled and tested through the deeper Torok formation.

In its proposed amendment, Shell said the mandate would "not only add significant additional costs to the planned program, but would require a significant amount of additional time on each well, possibly jeopardizing a second well and limiting the time available for testing and assessing the primary target — the Nanushuk."

Additionally, the company said that the Torok formation has not been shown "definitively" to be productive in the area of the Western Harrison Bay leases. Imposing a condition requiring drilling through the Torok "adds significantly to the risk of the drilling program and makes it more difficult to attract additional project participants."

However, Shell said the Torok could "certainly become the target of future evaluation if the results of the initial Western Harrison Bay unit drilling program" and future seismic data indicate there is "perspectivity within the Torok."

"Finding more shallow Nanushuk oil (in the Western Harrison Bay unit) that has the potential to be quickly brought into development and production alongside the two other large Nanushuk discoveries in the vicinity" (Pikka and Willow) would "greatly benefit the state and local communities in terms of increased reserves leading to increased future royalties and taxes, greater competition for state acreage, and expanded employment opportunities and demand for services on the North Slope." ●

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OIL PRICES

mark on Oct. 11 — briefly overtaking ANS, the same day WTI closed above the psychologically meaningful $80 mark, jumping $1.17 to $80.82.

On Oct. 12, ANS crossed above $83, up 63 cents to $83.61. Brent fell 23 cents to close at $83.42.

Over the five trading days, ANS has trended above and remains above Brent, likely due to competition from Asia for Pacific cargoes that might have otherwise landed on the U.S. West Coast to compete with ANS.

'Complete rubbish ... and tittle-tattle'

Meanwhile Brent prices were soothed by assurances from Russia President Vladimir Putin that Russia would not withhold natural gas supplies from Europe this winter as a political weapon.

Putin said such claims were "complete rubbish ... and politically motivated tittle-tattle."

In opening remarks to Russian Energy Week Oct. 13 in Moscow, Putin blamed the current crisis on Europe, according to a BBC report.

After a cold winter Europeans had not pumped sufficient volumes of gas into storage facilities, Putin said.

Russian majority state owned Gazprom is supplying gas to Europe at maximum levels under existing contracts, and is ready to provide more if requested, he said.

"We will increase by as much as our partners ask us," Putin said. "There is no refusal, none."

The wholesale price of natural gas in Europe has increased by 250% since January.

The spike in gas prices is the result of "systemic flaws in European energy," Putin said, blaming the rising share of renewables in Europe's energy mix, according to an Argus report.

Reduced wind generation this summer boosted the price of electricity and, in turn, gas, Putin said.

Gas will play a larger role in the global energy mix as oil and coal lose market share, he said, adding that Russia will also play a part in the development of hydrogen and ammonium as energy sources.

Putin said activation of the Nord Stream 2 gas pipeline — once European regulators sign the paperwork — could solve supply problems in Europe.

Nord Stream 2 will carry natural gas from Russia to Germany, bypassing Ukraine.

In Russia Energy Week comments, Putin said Nord Stream 2 was "a commercial project." Putin said that he is "100% certain" that if the pipeline were functioning, that would ease Europe's energy problems.

Bitter winter weather, however, could raise supply problems that pipeline capacity can't solve.

Gazprom's production in September was at the highest level in more than a decade for this time of year, but its exports to key foreign markets were at the lowest level since 2016, Bloomberg reported based on historic data and calculations compiled by it and Interfax.

Gazprom said it was overwhelmed by domestic demand, largely due to a massive storage-injection campaign in Russia, and a scattered spate of cold September weather.

"Russia fully fulfills its contractual obligations to our partners, including in Europe, and ensures guaranteed, uninterrupted gas supplies in this direction," Putin said in Russia Energy Week remarks.

Putin said price instability isn't in the interests of anyone, including producers.

"A sharp, multiple increase in energy prices puts enterprises, the economy, and utilities into a situation of radically increasing costs, forcing them to reduce energy consumption, which means that high price conditions can eventually turn into negative consequences for everyone, including producers," Putin said.

OPEC weighs in

The Organization of the Petroleum Exporting Countries may have helped to cool price action on Oct. 13, with a new more pessimistic outlook for 2021 prices contained in its October OPEC Monthly Oil Market Report.

OPEC estimated that world oil demand will increase by 5.8 million barrels per day in 2021, revised down from 5.96 million bpd in its previous month's assessment.

"The downward revision is mainly driven by lower-than-expected actual data for the first three quarters of this year, despite healthy oil demand assumptions going into the final quarter of the year, which will be supported by seasonal uptick in petrochemical and heating fuel demand and the potential switch from natural gas to petroleum products due to high gas prices," OPEC said.

For 2022, the OPEC estimate of world oil demand growth is unchanged at 4.2 million bpd, OPEC said, resulting in global demand next year averaging 100.8 million bpd.

OPEC's global economic growth forecasts for both 2021 and 2022 remain unchanged from the last month's assessment at 5.6% and 4.2%, respectively, it said. However, due to slowing third quarter 2021 momentum, the U.S. economy forecast for 2021 was revised lower — to 5.8% from 6.1% — while the forecast for 2022 remains unchanged at 4.1%. ●

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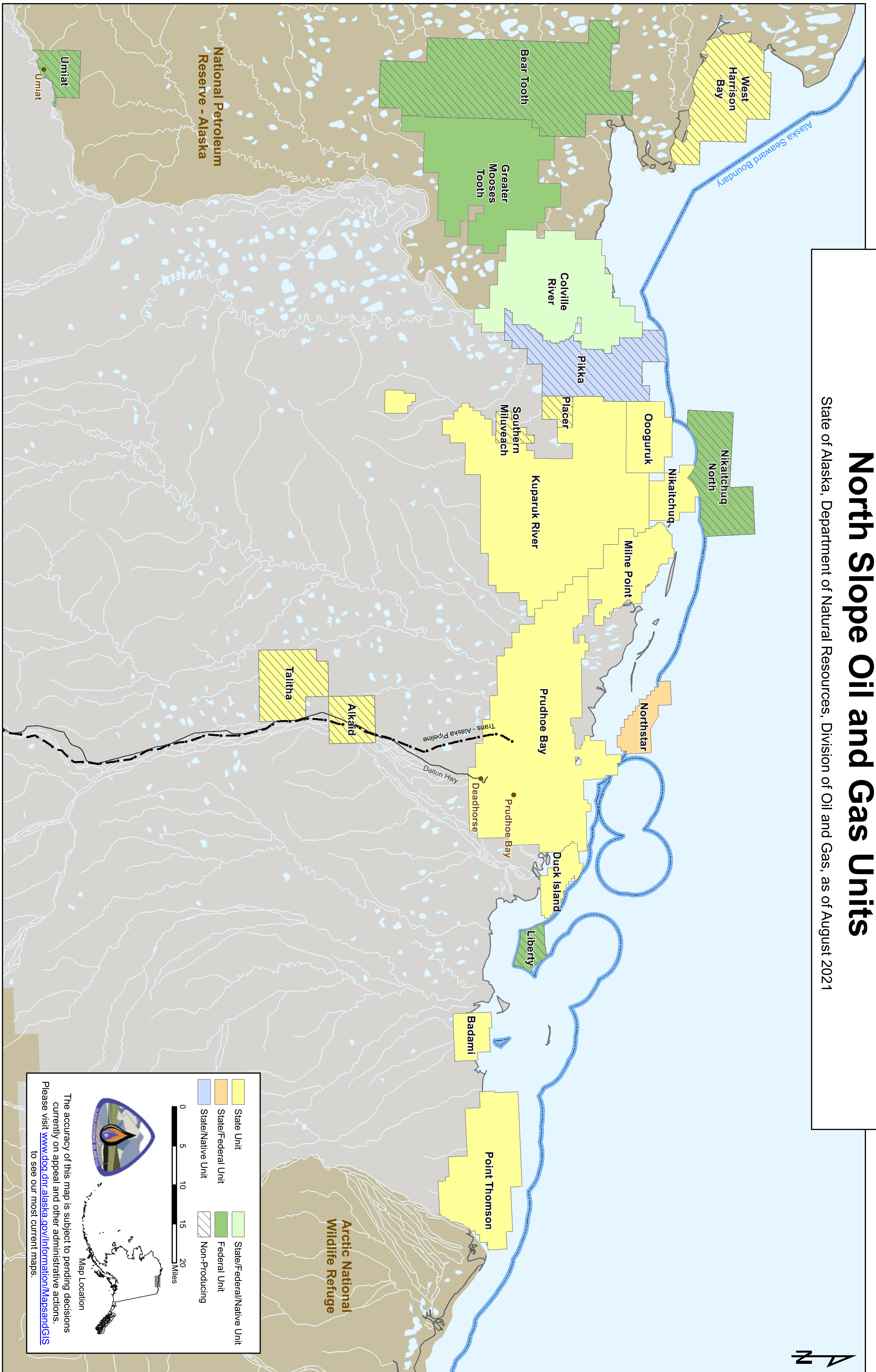
North Slope Oil and Gas Units
State of Alaska, Department of Natural Resources, Division of Oil and Gas, as of August 2021
Alaska Seaward Boundary
West Harrison Bay
Bear Tooth
Greater Mooses Tooth
Umiat
Umiat
National Petroleum Reserve - Alaska
Colville River
Pikka
Placer
Southern Miluveach
Oooguruk
Nikaitchuq North
Nikaitchuq
Kuparuk River
Milne Point
Talitha
Alkaid
Trans - Alaska Pipeline
Dalton Hwy
Prudhoe Bay
Northstar
Deadhorse
Prudhoe Bay
Duck Island
Liberty
Badami
Point Thomson
Arctic National Wildlife Refuge
State Unit
State/Federal Unit
State/Native Unit
State/Federal/Native Units
Federal Unit
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