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page 3 EIA forecasts $61 Brent this year, US crude averaging 11.1 million bpd

Merlin well spud; 12 states sue on Biden climate executive order

88 ENERGY STARTED DRILLING its Merlin 1 exploration well in the National Petroleum Reserve-Alaska on March 10, but because of delays caused by a Biden executive order, the second Peregrine project well, Harrier 1, is "unlikely" to be drilled this winter, the company said in an operations update.

Merlin 1, which is being drilled with Rig 111 by one of the company's Alaska subsidiaries that is headed by Alaska geologist Erik Opstad, will initially be drilled to 1,500 feet, then surface casing will be installed and the blow out preventer system tested, all of which is expected to take

see **INSIDER** *page 12*

Court approves expedited briefing schedule in Willow case

The federal District Court in Alaska has agreed to a request for expedited briefing schedules in two parallel court cases challenging the legality of Bureau of Land Management approval of ConocoPhillips' Willow oilfield development in the National Petroleum Reserve-Alaska. In a March 3 court order District Court Judge Sharon Gleason agreed to a schedule proposed by the parties in the cases — the schedule would require the completion of all briefings and responses by June 1.

In an earlier court filing ConocoPhillips had requested an expedited decision by July 1 in the cases, saying that a later decision would likely result in the loss of the off-road construction season for the Willow project in the winter of 2021-22.

see **WILLOW SCHEDULE** *page 10*

Furie requests reconsideration of AOGCC order on old inlet wells

JOHN HENDRIX

Furie Operating Alaska has filed a motion for reconsideration of the Alaska Oil and Gas Conservation Commission's March 1 order denying the company's request that no further site clearance work be required on three Cook Inlet wells drilled by the company under previous owners.

The commission agreed with Furie's request to change the status of the three wells at the offshore Kitchen Lights unit — KLU 1, KLU 2A and KLU 4 — from suspended to plugged

see **FURIE REQUEST** *page 10*

Bill would allow subsurface only, Kachemak Bay gas-only leasing

There is an area of state waters off the southern Kenai Peninsula closed to oil and gas leasing, but adjacent to an area where Hilcorp Alaska is developing the Seaview unit — a natural gas unit expected to come online later this year.

If the natural gas resource at Seaview extends out under state waters in the inlet, the area immediately offshore the Seaview unit could not be leased because it lies within the Kachemak Bay Oil and Gas Closure Area, which means the state could not collect lease bids, rental payments and royalties from the area.

The administration has introduced a bill which would allow the Alaska Department of Natural Resources, Division of Oil and Gas, to issue gas-only leases allowing drilling from

see **LEASING BILL** *page 9*

EXPLORATION & PRODUCTION

Focus on North Fork

Gardes signs gas contract, works 3D to generate its own ideas for unit

By KAY CASHMAN
Petroleum News

BOB GARDES

MARK LANDT

Vision Resources, a Gardes Holdings company, has entered into a five-year natural gas sales and purchase agreement with Alaska Pipeline Co. that will result in APC's utility affiliate Enstar Natural Gas Co. distributing gas from Vision's North Fork unit. The field is north of Homer on Alaska's southern Kenai Peninsula.

The agreement was filed in February by Enstar with the Regulatory Commission of Alaska, which oversees supply contracts for regulated utilities.

Enstar provides natural gas distribution service to the municipality of Anchorage and portions of the Matanuska-Susitna and Kenai Peninsula boroughs.

Gas deliveries are expected to begin May 11, when the current contract with seller Cook Inlet Energy expires. The starting price will be $7.30 per thousand cubic feet. After the first year the gas price will increase annually by 7 cents per mcf through the end of the contract for a final price

see **NORTH FORK FOCUS** *page 8*

FINANCE & ECONOMY

ANS near 2-year highs

OPEC+, Saudis shock markets; carry production cuts unchanged into April

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude inched up 16 cents March 10 to $67.51 per barrel, ending a two-day slide that began on March 8 following a spectacular week of gains that saw ANS close over $69 on March 5.

Brent and West Texas Intermediate traced a similar pattern, with Brent rising 43 cents to close at $67.90 March 10, while WTI rose 43 cents to $64.44.

ANS leapt $2.84 March 4 to close at $67.05 after the Organization of the Petroleum Exporting Countries and its allied producing countries decided to hold existing production curbs in place, while Saudi Arabia announced it would extend its two-month voluntary 1 million barrel per day production cut into April.

The success rate of global conventional oil and gas exploration has declined in recent years, most notably the success of onshore wildcat wells, according to a March 5 Rystad Energy report.

Brent jumped $2.67 to close at $66.75 and WTI jumped $2.55 to $63.83 on the news, reaching the highest levels since April 2019.

On March 5, ANS rose $2.13 to $69.18, Brent

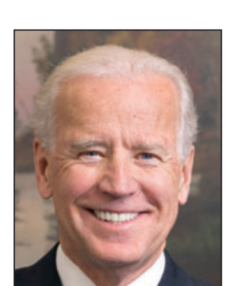
see **OIL PRICES** *page 11*

GOVERNMENT

'Special bond' under stress

Canada ready to do battle over future of Line 5, citing energy security threat

By GARY PARK
For Petroleum News



JOE BIDEN

JUSTIN TRUDEAU

Canadian Prime Minister Justin Trudeau ended a one-hour phone conversation with President Joe Biden on Feb. 23 telling the world he had a new and trusted friend in the White House.

It's possible the return to "normal," after four years of Trudeau's sniping with Donald Trump, may last as long as a ceasefire in Afghanistan.

The "special bond" the Canadian leader apparently believed he had established is about to be tested, with Biden holding the key — if he even believes that is necessary — to persuading his close ally, Michigan Gov. Gretchen Whitmer, to drop her plans to shut down Enbridge's Line 5 on May 13.

The new president is seen in Canada as its only hope of resolving this dispute, regardless of Michigan's state control over the pipeline.

Christopher Sands, director of the Canada Institute at the Wilson Center in Washington, D.C., said that Biden can settle matters even if he can't legally override Whitmer's move to legislate the

see **LINE 5 FUTURE** *page 8*

● EXPLORATION & PRODUCTION

US drilling rig count up by one to 403

By KRISTEN NELSON

Petroleum News

The Baker Hughes U.S. rotary drilling rig count, 403 for the week ending March 5, was up by one from the week ending Feb. 26 and down 390 from a count of 793 a year ago.

When the count bottomed out at 244 in mid-August last year, it was not just the low for 2020, but the lowest the 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 when it gained back 10 rigs.

The March 5 count includes 310 rigs targeting oil, up by one from the previous week and down 372 from 682 a year ago, 92 rigs targeting gas, unchanged from the previous week but down 17 from 109 a year ago, and one miscellaneous rig, unchanged from the previous week and down one from a year ago.

Sixteen of the holes reported March 5 were directional, 362 were horizontal and 25 were vertical.

Alaska unchanged from previous week

Texas (202), with the most active rigs, was up by five from the previous week, the only state with a week-over-week increase.

Louisiana (45) was down by two rigs from the previous week; New Mexico (61) and North Dakota (13) were each down by a single rig.

Counts in all other states remained unchanged: Alaska (3), California (7), Colorado (8), Ohio (7), Oklahoma (17), Pennsylvania (20), Utah (3), West Virginia (11) and Wyoming (5).

Baker Hughes shows Alaska with three rigs active March 5, unchanged from the previous week and down by seven from a year ago, when the state's count stood at 10.

The rig count in the Permian, the most active basin in the country, was up by three from the previous week at 211, but down by 204 from a count of 415 a year ago.

International

Baker Hughes international rig count — which excludes the U.S. and Canada — averaged 701 in February, the company said in a March 5 release, up 24 rigs from an average 677 active rigs in January, and down 384 from a February 2020 average of 1,085 rigs.

The U.S. count averaged 398 in February, up 29 from a January average of 369 and down 393 from a February 2020 average of 791. The Canadian count averaged 171 in February, up 34 from January and down 78 from a

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● FINANCE & ECONOMY

EIA forecasts $61 Brent in ’21, $59 in ’22

US crude expected to average 11.1 million bpd this year, rising to 12 million bpd in 2022, reflecting higher expected crude prices

By KRISTEN NELSON
Petroleum News

U.S. crude oil production is expected to average 11.1 million barrels per day this year, rising to 12 million bpd in 2022, the U.S. Energy Information Administration said March 9 in its Short-Term Energy Outlook.

The agency estimates that U.S. crude production averaged 10.4 million bpd in February, down 0.5 million from its estimate for January production, with most of that decline reflecting February’s cold temperatures, particularly in Texas.


STEVE NALLEY

“Unlike the relatively winterized oil production infrastructure in northern areas of the country, infrastructure in Texas, such as wellheads, gathering lines, and processing facilities, are more susceptible to the effects of extremely cold weather,” the agency said.

EIA is forecasting U.S. crude production will rise to almost 11 million bpd in March.

The 2020 average was 11.3 million bpd, down from a 2019 average of 12.2 million bpd, with the 2021 forecast in March up 0.5 million bpd from the February forecast.

“EIA increased our forecast for U.S. crude oil production in 2022 in response to the expected increase in prices,” EIA Acting Administrator Steve Nalley said in a statement accompanying the STEO release. “We now expect U.S. production to reach 12.0 million barrels per day in 2022.”

Brent spot prices

EIA said COVID-19 and related reduced economic activity “caused changes in energy demand and supply during the past year and will continue to affect these patterns in the future.”

Brent crude oil spot prices averaged $62 per barrel in February, up $8 from the January average and up $7 per barrel from February 2020, the agency said, with the rising prices in February reflecting expectations of rising oil demand as COVID-19 vaccinations and global economic activity increase, combined with ongoing supply limitations by the Organization of the Petroleum Exporting Countries and partners, and disruptions in supply from extreme weather in the U.S.

“EIA expects March and April Brent crude oil prices to average $67 per barrel — which is $7 and $12 higher, respectively, than forecast last month — because of continuing production restraint from OPEC and its partner countries,” Nalley said.

The agency said IHS Markit is forecasting increased economic activity. The U.S. gross domestic product is projected to grow by 5.5% this year, up from the 3.8% growth assumed in the February STEO, and by 4.2% next year, which remains “largely unchanged” from its February forecast, EIA said.

Global GDP, estimated by Oxford Economics, is also expected to be stronger than in the February STEO, contributing to 0.3 million bpd more growth in global liquid fuels consumption in 2022 than in the February STEO.

EIA said it is forecasting similar overall consumption in 2021 “compared with the February STEO because the effects of stronger economic activity are offset by a reduced expectation for global jet fuel consumption.” The agency said it reduced expectations for jet fuel consumption this year “in response to lower than expected first-quarter flight activity, along with reduced air travel expectations from the International Civil Aviation Organization during the second quarter of 2021.”

Natural gas

“Henry Hub natural gas spot prices increased to $5.35 per million British thermal units in February, the highest monthly average since February 2014,” Nalley said.

This was up from a January average of $2.71 per million Btu, the agency said, with the higher February prices attributed to much colder-than-normal temperatures in most of the country.

“Price effects were amplified because the rise in demand occurred amid a drop in natural gas production due to well freeze-offs,” EIA said.

The Henry Hub spot price is expected to decline to an average of $2.88 per million Btu in the second quarter, and to average $3.14 per million Btu this year, up from the 2020 average of $2.03 per million Btu. The continued growth in liquefied natural gas exports, combined with relatively flat production, are expected to contribute to a rise in Henry Hub spot prices to an average of $3.16 per million Btu in 2022.

U.S. natural gas consumption is expected to average 82.5 billion cubic feet per day this year, down 0.9% from 2020, reflecting less natural gas consumed for electric power because of higher prices compared to 2020.

EIA said it estimates that natural gas consumption in February, 111.8 bcf per day, was the highest on record because of cold weather and increased natural gas demand for heating and power generation.

The agency said its forecast is that U.S. production of dry natural gas averaged 87.8 bcf per day in February, down from 92.4 bcf per day in December — the most recent month for which there is final data, with the decline “mostly a result of freeze-offs, which occur when water and other liquids in the raw natural gas stream freeze at the wellhead or in natural gas gathering lines near production activities.”

The U.S. exported an average of 7.5 bcf per day of LNG in February, down 23%, 2.3 bcf per day, from January, with exports “affected by the logistical constraints associated with suspending piloting services

see **EIA OUTLOOK** *page 4*

EXPLORATION & PRODUCTION

Hilcorp adds wells, workovers to Milne POD

The Alaska Division of Oil and Gas has approved an amendment to Hilcorp Alaska’s 2021 Milne Point unit plan of development adding five wells, as many as 11 well workovers, coiled tubing drilling and facility projects.

The 2021 39th POD, approved in November for work from Jan. 13, 2021, through Jan. 12, 2022, already included up to 17 new wells at Milne Point — Schrader Bluff I Pad and J Pad injectors and producers — up to 20 well workovers and a number of key facility projects (see stories in Oct. 18 and Dec. 6 issues of Petroleum News).

The POD amendment, approved Feb. 24, adds to the work already approved:

•A proposed five-well drilling program at S Pad — two injectors and three producers.

•Completion of up to 11 well workovers with the Doyon 14 rig.

•A coiled tubing sidetrack drilling program — two wells at C Pad; four wells at F Pad; and one well at L Pad.

•Major facility projects — transformer replacement on Tract 14; S Pad header expansion and polymer facility project; and an upgrade to the L Pad polymer systems.

The proposed addition to the 2021 Milne drilling program would bring that total to 22 wells; well workovers could total 31.

Hilcorp came to Alaska in 2011 and 2012 with significant acquisitions in Cook Inlet, picking up assets formerly operated by Union Oil Company of California and Marathon Oil Corp. Hilcorp is currently the dominant Cook Inlet oil and gas producer.

A 2014 deal with BP, which gave Hilcorp entre to Alaska’s North Slope, included 50% working interest ownership and operatorship at Milne. Hilcorp renewed the focus on Milne’s viscous oil, investing some $700 million in conjunction with BP and drilling more than 60 new wells. Production from Milne averaged 18,400 barrels per day when Hilcorp became operator and in January averaged more than 35,000 bpd. As part of its 2019 purchase of BP’s assets in Alaska, finalized in 2020, Hilcorp became 100% working interest owner at Milne Point.

—KRISTEN NELSON

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RIG COUNT

February 2020 count of 249.

The total worldwide count averaged 1,270 in February, up 87 rigs from an average of 1,183 in January and down 855 from a February 2020 average of 2,125.

Baker Hughes has issued weekly rig counts for the U.S. and Canada since 1944 and began issuing international rig counts monthly in 1975. ●

Contact Kristen Nelson
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● UTILITIES

A world leader in microgrids

Can Alaska export and monetize its state-of-the-art expertise in the implementation and operation of small, self-sufficient electrical systems?

By ALAN BAILEY
For Petroleum News

Having become a world leader in the implementation of microgrids for the distributed supply of electricity, Alaska has an opportunity to capitalize on that expertise, using its first mover status to benefit from the economics of exporting its capabilities, Gwen Holdman, director of the Alaska Center for Energy and Power, University of Alaska Fairbanks, told the Commonwealth North Energy Policy Study Group on Feb. 26. Holdman compared Alaska with Iceland, a country with a very small population that has been able to export its expertise in geothermal energy.

ACEP has formed the Alaska Microgrid Group and is working with several Alaska electrical associations, to figure out ways to export and try to monetize Alaska expertise, Holdman said.

Widely dispersed communities

With a small population spread around widely separated communities, the provision of electricity supplies in Alaska has involved the construction of local microgrids, typically using some blend of traditional oil-fueled generation and renewable energy, mostly in the form of wind and solar energy.

Commenting that the recent power supply problems in Texas resulted from a lack of resilience of the Texas grid, in the face of unanticipated events, Holdman argued that the type of distributed microgrid configuration found in Alaska brings resilience to the overall power supplies — a power outage in one part of the state does not impact other parts of the state. In that respect, Holdman even characterized the Alaska Railbelt electrical system as a system of interconnected microgrids in the various load centers — although, for example, Fairbanks obtains some power from the south via a long-distance transmission line, the Fairbanks region has sufficient capacity by itself to withstand a power outage in the Anchorage region or elsewhere.

> ***Research is in progress into the development of tiny 1- to 10-megawatt reactors that would be buried in the ground when in use. Operating as something akin to nuclear batteries, these would have lives of 10 to 20 years, after which they would be replaced by new units.***

However, this type of resilience, as distinct from minute-by-minute reliability, does come at a cost, given the need for local power generation capacity that will typically exceed the capacity necessary to support the total load across a complete region, Holdman commented.

Helping communities

ACEP constantly seeks ways of helping communities find new solutions for improving their electricity supply arrangements and minimizing the cost of heat and electrical power for residents.

In Kake, in the Panhandle, and in Kotzebue in Northwest Alaska, for example, ACEP is working with local organizations to evaluate the use of air source heat pumps to heat residences. A heat pump, a kind of reversed air conditioner, can be a more efficient means of heating a building than a conventional electric heater. In Kotzebue ACEP has installed devices that can non-invasively measure household fuel oil consumption, to gain a better understanding of household heat use. Another ACEP device can monitor power outages and power quality data.

In the Railbelt, ACEP has been working with Matanuska Electric Association to implement combined solar and battery systems at the far end of a long transmission line, particularly in the Talkeetna area, to address power supply reliability issues at the ends of long lines, Holdman said.

Energy storage

Energy storage, often using batteries, is a key to achieving supply reliability in an isolated microgrid. But batteries are typically expensive — APEC has been working with Alaska Village Electric Cooperative, for example, to figure out how to minimize the amount of storage needed to assure electricity supply reliability. And ACEP has developed computer software that can help determine right-sized solutions, Holdman said.

Another potential energy storage option consists of using surplus electricity to generate heat that can be stored for future use in an electric boiler, for example. Electrically pumped hydro can also store excess electrical power.

There may be future opportunities to reduce electrical costs for remote communities by connecting some communities' electrical systems using buried, medium-voltage, DC power transmission lines — vehicle technology used in rural Canada to install long-distance, remote fiber optic cable lines might be used for this, Holdman said.

Micro nuclear reactors

There is also much interest in the future potential to use micro nuclear reactor technologies for remote electricity supplies. Research is in progress into the development of tiny 1- to 10-megawatt reactors that would be buried in the ground when in use. Operating as something akin to nuclear batteries, these would have lives of 10 to 20 years, after which they would be replaced by new units. However, although these systems may be tested in demonstration projects in a few years time, commercial implementation would still be quite a few years into the future.

Socio-economic issues

Holdman said that ACEP is working with researchers across the Arctic, looking into socio-economic issues associated with electricity supplies in remote communities, especially indigenous communities. One interesting issue, for example, is the connection between electrical power use and heating, in terms of food supplies and community sustainability. For example, a reduction in people's fuel oil bills can enable the purchase of fuel for use in subsistence activities, Holdman commented.

And the operation of modern microgrids involves expertise in the ways in which this type of electrical system differs from a more traditional, large scale system. Whereas a traditional system typically involves generators with much rotating inertia, a microgrid with renewable energy sources acts very differently, Holdman said.

By exporting Alaska expertise in these types of issue to other parts of the world, it is possible to enable other projects to benefit from Alaska's lessons learned while also ensuring that Alaska remains at the forefront of microgrid technology, Holdman suggested. ●

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EIA OUTLOOK

on several days at some U.S. LNG export ports located in the Gulf of Mexico because of inclement weather," and several U.S. LNG export facilities experiencing lower natural gas feedstock supply in mid-February "following declines in natural gas production because of extremely cold weather."

The agency said it expects LNG exports to continue a seasonal decline from March through May, with the average for that period of 7.8 bcf per day. ●

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● EXPLORATION & PRODUCTION

Hilcorp files PODs for small inlet fields

Ivan River and Lewis River are two of smaller gas fields in Cook Inlet; Ivan River production increased substantially last year

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has filed plans of development with the Alaska Division of Oil and Gas for two small Cook Inlet gas fields, Ivan River and Lewis River.

Alaska Oil and Gas Conservation Commission records show that, this January, the two fields combined accounted for some 3.2% of the natural gas produced in Cook Inlet.

The POD for Ivan River, submitted March 1, is the 51st for that unit and covers June 1, 2021, through May 31, 2022.

In the previous plan, the 50th, Hilcorp had not proposed any long-range development plans nor did it have any planned exploration or delineation activities.

Ivan River produces from the Sterling-Beluga and Tyonek participating areas and Hilcorp said that cumulative gas production in 2020 was 793.8 million standard cubic feet.

There are also two wells, IRU 14-31 and IRU 13-31, used as disposal wells for the fields the company operates on the west side of the inlet — Lewis River, Pretty Creek, Ivan River and Stump Lake.

The company said it completed three intervention jobs during the 2020 POD period:

•The Tyonek sands were isolated in IRU 11-06 and the Sterling A5 was perforated. After the work was performed in July the well initially came online at 4.4 million standard cubic feet per day.

•The Sterling sands were isolated in IRU 11-06 and the Sterling B2 was perforated in September, with the well initially coming online at 3.1 million standard cubic feet per day.

•The Sterling B1 was perforated in IRU 41-01 this February and the well initially came online at 4.2 million standard cubic feet per day.

The company said there were no major facility improvements in the 2020 POD period.

AOGCC records show that Hilcorp increased produc-

see **HILCORP PODS** page 7

● FINANCE & ECONOMY

Embracing ESG trend in Alberta oil patch

Premier Jason Kenney does U-turn to promote ESG standards; launches secretariat in hopes of stemming tide of investment bailout

By GARY PARK
For Petroleum News

A fad or a fixture? That's the question swirling through corporations and governments these days as decision-makers — like it or not — get to grips with three letters, ESG, and determining whether the scoring methodology associated with the annual evaluation of environmental, social and governance performance has become a vital cog in the industry machine.


JASON KENNEY

The answer seems increasingly clear: Get used to ESG without delay or pay the price.

What is already clear is that companies and investors are scrambling to get on the bandwagon, prodded by government actions to tighten the evaluation of thousands of factors that affect ESG scores.

S&P Global has offered a guide to help participants take control of their ESG performance by offering an insight that "gives you the power to determine, benchmark and communicate ESG opportunities and risks to avoid pitfalls and accelerate progress."

Alberta opens ESG office

In Canada's hydrocarbon industry, the emergence of ESG gained serious momentum in late February when the Alberta government announced in its 2021-22 budget that it was opening an office to promote ESG measures in hopes of stemming the tide of investment bailout from the province's oil sands and its wider energy sector.

That comes only two years after Premier Jason Kenney called investor concerns about climate risks "the flavor of the month."

A new ESG secretariat in the Alberta government will have an initial C$1 million infusion and a mandate to stretch its role to other industries by coordinating policy action and advocacy efforts.

Kenney told the Globe and Mail that the Alberta government, after 15 to 20 years of promoting economic development in different ways, is now "upping our game."

"Part of our message is: To focus only on emissions in the broader ESG spectrum is not the right path," he said.

Kenney has already carried that message to London when he met with banks and investment houses in an effort to demonstrate that oil sands producers are making strides to reduce per-barrel greenhouse gas emissions and on other environmental issues.

Energy Minister Sonya Savage, who was a senior executive at Enbridge before entering politics, was a first-hand witness to a growing emphasis on ESG which she said has now become a "fundamental and central thing for the entire industry."

Sluggish response to ESG

However, S&P Global, in its latest Sustainability Yearbook, which awards companies that have demonstrated superior performance, reports a somewhat sluggish response to ESG.

More than 7,000 companies were assessed in 2020, but only 631 posted ESG scores that gained them a place in the Yearbook.

PwC, the global professional services network, said ESG metrics have become leading guideposts for investment, but noted that over the last decade awareness of the benefits of climate action has drifted in the opposite direction among Canadian CEOs from 21% to 18%.

The firm said it's time for those leaders "to seize on ESG as an opportunity to embed longevity and resilience into rapidly changing industries and business models."

Ben Brunnen, vice president of oil sands at the Canadian Association of Petroleum Producers, showed no sign of disagreeing with PwC's stand.

He said the new Alberta secretariat, regardless of its modest beginnings, could fill a void in defining ESG metrics and tracking how the petroleum industry is meeting its goals.

"If we can get some objective, consistent, complete and compatible data on ESG performance, our industry can … start to demonstrate its performance to international markets in order to attract capital," he said.

In fact, despite PwC's observations, BMO, based on a third-party assessment, said Canada is producing some of the "most ethical and environmentally sustainable oil barrels in the world," ranking No. 1 in all ESG categories among nations with the largest oil reserves.

The Alberta government has enlisted the help of the Eurasia Group, a New York-based political risk consultant, for help in promoting investments in the energy sector and navigating investors' ESG frameworks.

Savage said a C$125,000 contract with Eurasia helped Alberta when it was "staring down negative oil prices and was not sure exactly where it was heading."

Eurasia said in a February report that ESG considerations in financial sector regulation present "one of the most substantive opportunities for President Joe Biden's administration to advance climate policy." ●

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● EXPLORATION & PRODUCTION

North Fork plan of development approved

Glacier asks delay in scheduled contraction to allow new owner, Gardes Holdings, to assess opportunities once state OKs transfer

By KRISTEN NELSON
Petroleum News

A Feb. 25 decision, signed by Alaska Division of Oil and Gas Director Tom Stokes, approved the 56th plan of development for the North Fork unit submitted by Cook Inlet Energy, a Glacier Oil & Gas Corp. company.

Glacier sold North Fork to Gardes Holdings Inc. in November (see story in Nov. 15 issue of Petroleum News), and the division has received notification from Cook Inlet Energy resigning as operator of the unit and appointing Gardes Holdings as the successor operator and a lease assignment application from CIE to Gardes for the state oil and gas leases associated with the unit.

The division said both notification and assignment are under review and will be addressed separately.

Vision Resources, a Gardes company, has signed a gas supply contract with Alaska Pipeline Co. which is before the Regulatory Commission of Alaska for approval (see story in this issue).

Pascal said CIE is requesting a one-year suspension in the contraction "to allow Gardes the opportunity to access options as a new operator and submit its own development plan to DO&G."

Contraction delay request

On Feb. 26 Glacier requested that the division delay contraction of the unit acreage at North Fork.

David Pascal, chief operating officer of Cook Inlet Energy, said the company is requesting the delay "in the scheduled contraction of the North Fork Unit" because the company is in the process of transferring North Fork unit ownership to Gardes Holdings "and this process is still under review and awaiting final approval from the Division of Oil and Gas."

Unit contraction is required after a unit has been in production for 10 years, at which point the unit is contracted to areas actually in production. Participating areas are required to be established for producing areas before sustained production can begin.

North Fork has just a single PA.

Pascal said CIE is requesting a one-year suspension in the contraction "to allow Gardes the opportunity to access options as a new operator and submit its own development plan to DO&G."

Unit formed in 1965

The division reviewed the history of the unit in the 56th POD approval decision.

It was formed as a federal unit in 1965 with Standard Oil Company of California as operator. The U.S. Department of the Interior's Bureau of Land Management and the state co-managed the original unit, which included two state and two federal leases, a total of 58,113.4 acres. In 2006 BLM waived its administrative rights and transferred the North Fork leases to the state.

The unit currently includes five state leases, a total of 2,601.84 acres, the division said. The unit's single participating area, the Gas Pool No. 1 PA, was established in 1965 covering 640 acres. In 2011 it was expanded to 800 acres, the same year in which sustained production was achieved.

Through the end of 2020, North Fork had cumulative production of 21.46 billion cubic feet of natural gas and 27,414 barrels of water, all from the original PA.

In 2014, CIE took over as operator at North Fork from Armstrong Cook Inlet.

Work at North Fork

The division said CIE completed some of the work proposed in its 55th POD. It added perforations to one of the wells in the field, and although the COVID-19 pandemic forced suspension of that work, CIE did accomplish modification of compression capabilities "to assist in extending the life of the wells" and used offsite disposal to assist in controlling water production, as well as identifying equipment and resources necessary to decrease system pressure at the facility.

April through December 2020, North Fork production totaled 0.92 billion cubic feet, compared to 1.02 bcf for the same period in 2019.

For the proposed 56th POD, "CIE has no specific plans for exploration or delineation," the division said, but will continue to evaluate opportunities to drill outside the existing PA, as well as "analyzing and optimizing" current production from the unit.

As with the 55th POD, the company said "additional drilling will depend on favorable economic conditions including the negotiation of a long-term gas sales contract."

The division approved the proposed 56th POD and said the plan protects the public interest "by maintaining and optimizing current production while evaluating future drilling opportunities." ●

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EXPLORATION & PRODUCTION

Vote on plan for thousands of California wells

By BRIAN MELLEY

Associated Press

A plan to fast-track drilling of thousands of new oil and gas wells over the next 15 years in California's prime oil patch was being considered March 8 by Kern County officials over objections by environmental groups.

The Board of Supervisors was poised to vote on a revised ordinance supported by the influential petroleum industry that creates a blanket environmental impact report to approve as many as 2,700 new wells a year.

The revision was necessary after a state appeals court ruled last year that a 2015 ordinance violated the California Environmental Quality Act by not fully evaluating or disclosing environmental damage that would occur from drilling. New drilling permits were not allowed while the county returned to the drawing board.

County Planning Director Lorelei Oviatt said the plan, which now fills 72 binders of documents, made 87 revisions, including creating larger buffers between homes and wells, muffling noise during drilling and putting a stricter limit on the number of new wells.

The ordinance approved in 2015 would have allowed up to 72,000 wells, but with a lower cap on annual approvals, that number is now reduced to about 43,000 new wells in the 20-year period ending in 2035.

"What we project is the worst case scenario on many issues," Oviatt said, adding that actual permit numbers in recent years were below the cap.

Petroleum producers, oil workers and industry and business groups spoke in favor of the measure, saying it would support high-paying jobs and produce oil under some of the most stringent environmental laws, instead of relying on dirtier imports.

Environmentalists, several residents and one farmer opposed it, saying the revisions did not address the concerns spelled out by a unanimous 5th District Court of Appeal in Fresno. Many, including several people speaking Spanish, spoke about how more oil drilling would exacerbate the notoriously bad air pollution in the San Joaquin Valley and make asthma cases worse.

Keith Gardiner, a farmer who successfully sued the county, said the new plan still falls short of providing protection for valuable agricultural land, which was one of the court's findings. He said the county had wasted valuable time and spent millions of dollars supporting its flawed environmental impact report, EIR.

"Whose fault is it?" Gardiner asked. "There are those that will say it's my fault, and the fault of the environmental groups. Don't blame us. This is your EIR. The courts have found it's your fault for not following the law."

Kern County, about 100 miles north of Los Angeles, is the state's leading fossil fuel producer and also a major agricultural area. About 1 in 7 workers in the county of 900,000 has a job tied to the oil industry.

The vote comes as the industry faces

Kern County, about 100 miles north of Los Angeles, is the state's leading fossil fuel producer and also a major agricultural area. About 1 in 7 workers in the county of 900,000 has a job tied to the oil industry.

challenges from lawmakers as well as ever-present opposition from environmental groups for creating air and water pollution and significant contributions to climate change.

Gov. Gavin Newsom ordered a ban on the sale of new gas-powered passenger cars and trucks by 2035. New legislation would ban all fracking by 2027, limiting a technique by energy companies to inject water, sand, gravel and chemicals in the ground at high pressure to extract hard-to-reach oil and gas.

The controversy over the ordinance started when the county amended its zoning code in 2015 to allow it to approve new oil and gas extraction permits after a review determined that applications would meet requirements set by a blanket environmental impact report. Environmentalists argued that a one-size-fits-all approach didn't address different factors that vary by location such as habitat or proximity to neighborhoods.

The ordinance was designed to avoid costly, time-consuming environmental reviews of individual wells and was approved despite "significant, adverse environmental impacts," the appellate court said.

"The ordinance's basic purpose is the acceleration of oil and gas development and the economic benefits that might be achieved by that development," the ruling said. "Its basic purpose is not the protection of the environment." ●

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HILCORP PODS

tion from the unit over the last year. In January 2020 Ivan River production averaged 316 thousand cubic feet, mcf, per day, 0.2% of Cook Inlet gas production. In January 2021, following the intervention jobs performed in 2020, Ivan River production averaged 6,267 mcf per day, 2.8% of Cook Inlet production.

In January 2020 Ivan River production averaged 316 thousand cubic feet, mcf, per day, 0.2% of Cook Inlet gas production. In January 2021, following the intervention jobs performed in 2020, Ivan River production averaged 6,267 mcf per day, 2.8% of Cook Inlet production.

2021 POD

In the 2021 plan, Hilcorp said it "is currently evaluating delineation drill well opportunities within the Sterling-Beluga and Tyonek Participating Areas," but does "not currently have any planned development activities for the unit during the 2021 POD period."

The company proposes to continue production from the Sterling-Beluga PA and the Tyonek PA "as needed, while continuing to utilize IRU disposal wells."

The company said it is evaluating a rig workover on IRU 11-06 to replace current tubing and "allow for future isolation of perforations within the well."

No major facility upgrades are planned for the 2021 POD, but the company said it "will pursue improvements through various well, infrastructure and facility repairs."

Lewis River

Hilcorp submitted the 46th POD for the Lewis River unit on March 1 — the plan covers June 2, 2021, through May 31, 2022.

In the previous, 2020 POD, there were no long-range proposed development activities nor any planned exploration or delineation activities.

Hilcorp said it planned to continue production from the Lewis River Gas Pool No. 2 PA and during 2020, cumulative production from the PA was 400 million cubic feet, with all production from a single well, the LRU C-01RD.

In the 2021 plan, Hilcorp said it is evaluating possible delineation well opportunities, but does not have any long-range proposed development activities planned for the POD period.

Production will be maintained from the Lewis River Gas Pool No. 2 PA.

No major facility upgrades are planned.

AOGCC records show Lewis River production averaged 1,465 thousand cubic feet, mcf, per day in January 2020, 0.7% of Cook Inlet production, dropping to an average of 953 mcf per day in January 2021, 0.4% of Cook Inlet gas production. ●

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LINE 5 FUTURE

effective end of Line 5's role in delivering 540,000 barrels per day of light crude and natural gas liquids to refineries and vital infrastructure in Ontario, Quebec, Ohio and other U.S. refineries and meet two thirds of Michigan's propane needs.

But Sands said Line 5 has not yet made an appearance on Biden's public agenda and is not likely to make one.

"We may have to re-examine whether Biden and Trudeau really do have this special relationship we've heard about, because so far it's all talk, no action," he told the Canadian Broadcasting Corp.

A spokesman for Alberta Energy Minister Sonya Savage said Alberta is engaged with lawmakers on both side of the Canada-U.S. border, reinforcing the importance of Line 5 as a responsible source of energy.

Unlike its lukewarm response to Biden's cancellation of permits for Keystone XL, the Trudeau government shows signs it is ready to wade into Line 5.

In the strongest language the government has yet applied to the dispute, Natural Resources Minister Seamus O'Regan said the continued operation of Line 5 is "non-negotiable" for Canada.

He vowed Canada takes threats "to our energy security very seriously" and would do whatever it could to scuttle Whitmer's plan.

"We are watching it on a minute-by-minute basis and we will be absolutely prepared to intervene at exactly the precise moment," O'Regan said.

At stake is the continued movement of crude oil and natural gas from Canada into the U.S., easily the largest source of export revenue for Canada.

Enbridge view

Enbridge has argued that there is no credible basis to revoke approvals to replace and reinforce a segment of Line 5 that runs under the Straits of Mackinac, which connects Lake Huron and Lake Michigan.

A go-ahead to build twin concrete tunnels under Mackinac was approved in 2018 by then-Gov. Rick Snyder and given a green light in January by Michigan environmental regulators. Even so, Enbridge still needs other federal and state approvals before proceeding.

The existing link has had no spills since it was completed in 1953.

It doesn't help the company's case that Whitmer is a close ally of Biden, who reportedly put her on a short list of four as his vice presidential running mate, then offered her a cabinet post, which she turned down in favor of remaining governor, and finally nominated her to serve as vice chair of the Democratic National Committee.

That has to be weighed against the importance of prolonging the life of Line 5, which meets 65% of Michigan's propane needs in the state's Upper Peninsula — far beyond Whitmer's voting base — and 55% of statewide needs.

Challenged to explain how Michigan would replace those feedstock supplies, Whitmer insisted the state has a number of options, without offering any specifics.

While vague on her alternatives, she was forced to sign an executive order on Feb. 20 declaring an "energy emergency to ensure adequate propane" supplies for Michigan for the foreseeable future.

"While I am confident that our state has the energy supply we need to get through these cold winter days, we aren't taking any chances after what happened in Texas this week," she said.

The order temporarily suspended restrictions on commercial driver hours to allow the immediate delivery of energy to homes and businesses "without delay or interruption."

Pressure building

Pressure to head off the looming Line 5 crisis is building on the Ontario government from companies which rely heavily on the pipeline for refinery feedstock and 100% of the jet fuel used at Toronto International Airport.

Enbridge estimated that if Line 5 is shut down, Ontario and Quebec, with a combined population of 23 million, will be unable to meet 45% of their crude needs.

Michael Grant, a senior official in the Department of Global Affairs told a committee of the Canadian Parliament on March 2, that the Trudeau government has reserved the right to invoke a 1977 bilateral pipeline treaty which allows Canada to request negotiations with the U.S. and, if necessary, resort to binding arbitration to resolve a dispute.

But, for now, Grant said the government is hoping that Enbridge, Ontario and Quebec can press U.S. officials "to find a solution."

Lawrence Herman, a Toronto-based international trade attorney, said the 1977 treaty set an objective of ensuring "uninterrupted transmission" of fuel sources.

Analysts say a shutdown of Line 5 would force Ontario and Quebec to import petroleum by rail, truck or tanker, a potentially more dangerous and environmentally damaging method of transport. ●

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NORTH FORK FOCUS

of $7.60 per mcf.

North Fork produced an average of 3,126 mcf of natural gas per day in December.

Under the leadership of Bob Gardes of Lafayette, Louisiana, Gardes Holdings acquired the North Fork gas field in September from Cook Inlet Energy, a Glacier Oil and Gas Co. It was Gardes Holding's first acquisition in Alaska. Bob Gardes views the Cook Inlet basin as one of the four top gas regions in the world and is interested in picking up more stranded gas properties in Cook Inlet and Interior Alaska.

That said, "for the next year or more" Vision is "focused on North Fork," Mark Landt, company vice president of land and upstream business development, told Petroleum News in a March 10 interview. "We see some definite opportunities to pursue there," he said, noting the company has a "full G&G staff" working on North Fork.

> *"Now that we have our plan of development for the unit approved with the Division of Oil and Gas … and have purchased 3D seismic … we are going to be working the 3D data and generating our own ideas going forward."*
> *—Mark Landt*

"Now that we have our plan of development for the unit approved with the Division of Oil and Gas (see story in this issue) and have purchased 3D seismic … we are going to be working the 3D data and generating our own ideas going forward."

Landt said Vision sees "additional gas to be recovered" at North Fork, mentioning the possibility of "additional sands" in the field and more workovers.

The 2,601.84 acre, five-lease North Fork unit, produces from a single participating area covering 800 acres.

Although North Fork was first unitized in 1965 by Standard Oil Company of California, Armstrong Cook Inlet, a Bill Armstrong company, first brought the field online in 2011. The plan of development that was approved Feb. 25 is the 57th POD for the unit.

Leaseholder Vision, Landt's history

Gardes Holdings is awaiting the lease assignments it applied for in November from Alaska's Division of Oil and Gas. Once it has those in hand, Landt said, the firm will assign the leasehold to Vision Resources, one of two companies Gardes formed in Alaska. The other is Vision Operating, which will operate the North Fork unit.

Landt, who is well known in Alaska's oil patch, began his career with ARCO where he spent 25 years in various land, negotiations, acquisition, business development, marketing and senior management positions in their Denver, Lafayette, Dallas, Houston, Anchorage, Bakersfield and Plano (International) offices.

He has more than 25 years of direct experience in Alaska and was based in Anchorage for five years.

After leaving the company, Landt cofounded Prodigy Alaska, Renaissance Alaska, Buccaneer Alaska and Stellar Oil & Gas, all focused on E&P in Alaska.

Hennigan's Alaska experience

Landt has previously worked with Stephen Hennigan, vice president of engineering for Gardes Holdings.

Per the company's website Hennigan is the lead on engineering, drilling and completions in Alaska.

He has a "40-year track record of success in the oil and gas industry throughout the Lower 48 and, importantly, the Cook Inlet of Alaska. Steve has been directly engaged in successful drilling and development of North Fork unit and other Cook Inlet fields since 2007, for previous operators and owners," having "institutional knowledge of North Fork," per gardesholdings.com.

Bob Gardes on Alaska

The same website touted Bob Gardes as having "over 40 years engineering, drilling, completions in the oil and gas industry" and being "a pioneer in lateral drilling and completions and coal-bed methane development world-wide with more than 3,000 wells drilled under his management and supervision."

His companies own "multiple drilling patented methodologies related to lateral drilling and completions," his website bio said.

Gardes views natural gas as the "fuel of the future "

"We hope to be gold star presence among oil and gas companies in Cook Inlet," he told Petroleum News in early

see **NORTH FORK FOCUS** *page 10*

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LEASING BILL

shore but no surface access to tracts in this offshore area.

Sponsor statement

In a sponsor statement Gov. Mike Dunleavy said "gas reservoirs in Cook Inlet do not abide by lines demarcated" in statute for the Kachemak Bay Oil and Gas Closure Area established in Alaska Statute 38.05.184. He said, "certain surface leases on both state and private onshore land in the Cook Inlet area have the potential to produce gas from adjacent deposits lying beneath the seabed," and without the proposed legislation, "the state may be left without a clear mechanism to collect royalties from gas being produced from such undersea areas by adjacent leaseholders."

The proposal would open a small area to non-surface leasing, specifically within Township 5 South, Range 15 West, Seward Meridian.

Lessees would be prohibited from using the surface of the leased area to drill for or extract gas, but the state would be able to collect royalties on gas that might otherwise be produced by adjacent leaseholders.

"By prohibiting surface use, the bill adequately protects the habitat while ensuring the state obtains its fair share of gas produced from state land," Dunleavy said.

The bill would add a section to the Alaska Land Act clarifying that "when a statute restricts the surface use of an oil and gas lease area, it does not also restrict subsurface uses unless specifically provided. Adding this section would pave the way to allow subsurface oil and gas leasing in additional areas in the future," he said.

Fiscal note

Senate Resources heard the bill, Senate Bill 62, on March 10 (the House version, House Bill 82, referred to the House Special Committee on Fisheries and to House Resources, had not yet been scheduled for a hearing when this issue of Petroleum News went to press).

A fiscal note signed by Tom Stokes, director of the Division of Oil and Gas, said the bill would not significantly alter department activities, "instead, it removes an artificial barrier to allowing the Division to offer leases for oil and gas exploration in a small portion of the Cook Inlet, adjacent to the current leasing program."

Committee hearing

Haley Paine, deputy director of the Division of Oil and Gas, told Senate Resources the bill would allow the division to capture revenue from state-owned resources which underlie lands restricted to surface use, while only allowing drilling and development from unrestricted land and not granting any right for use of the surface of the restricted land.

The lands made available for subsurface only leasing in the bill are adjacent to active development at Seaview, she said, and she noted that at the Cosmopolitan unit to the north, all the resources are on state offshore leases but are being developed from onshore.

Revenues available from surface-use restricted lands could include lease sale bids, annual rental payments and royalties.

Paine said modern drilling technology enables the development of oil and gas from adjacent lands with no impact to the surface of the subject land and said the state would benefit from the ability to capture revenue through development of state resources with no impact to the surface of projected lands using established regulatory methods.

The main concern is to have a mechanism for collecting royalties and she said if unleased land is drained from adjacent leases, royalties may not be paid or revenue could be diminished and remedy might have to be sought through the Alaska Oil and Gas Conservation Commission.

Paine noted that the division can't exercise all of its regulatory authority over unleased acreage and told the committee the lease is the primary mechanism for enforcing mitigation measures and for sharing of drilling and reservoir data.

Bill specifics

The bill applies specifically to the area within Township 5 South, Range 15 West, Seward Meridian and would authorize gas-only leases. Paine said the intention of the bill is to provide a general framework, and any similar area identified in the future with restricted surface access and resources adjacent to state onshore leases from which drilling and development could occur would require a separate bill.

She said the bill creates an opening in case of future opportunities but is targeted to the area specified in the bill.

—KRISTEN NELSON

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Petroleum news — Oil Patch Bits

Lynden delivers COVID-19 vaccine to Western Alaska

As reported by Lynden News March 3, since mid-December Lynden has been assisting with the distribution of equipment to administer the COVID-19 vaccine, but now the shipments contain the vaccine itself. Each morning Lynden International District Operations Manager Bob Barndt gets a phone call alerting him to an incoming shipment arriving in Anchorage from Louisville, Kentucky. Barndt meets the plane and personally transfers the boxes of vaccine to Alaska Airlines where they are checked in as critical care shipments — the highest level of service available. After arriving in Bethel, Alaska, the Lynden agent receives the boxes and hand delivers them to hospitals in Bethel, Nome, Kotzebue and Barrow for distribution to village elders and front-line workers in those communities.

"For over 30 years, we have managed deliveries to remote Alaska communities," Barndt explains, "but the vaccine shipments are different than anything else we have handled." Lynden provides white-glove service for each 40-pound box which is red-flagged as hazmat material. The vaccine is packed in dry ice and each box contains a GPS tracking device and temperature monitor.

The vaccine deliveries will continue this year along with personal protective equipment such as gowns and gloves to protect those administering the drugs. Boxes of dry ice are sometimes shipped along with PPE to ensure that the vaccine remains temperature controlled at destination.

In 2009, the State of Alaska also relied on Lynden International to distribute the H1N1 vaccine to more than 400 locations.

Companies involved in Alaska's oil and gas industry

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FURIE REQUEST

and abandoned.

Furie had also requested that the commission not require further site clearance work. When the wells were drilled, they were left with casing rising 15 feet above the seafloor, based on stated intent of the previous unit owner to re-enter the wells.

The commission also required Furie to provide well location information to the National Oceanic and Atmospheric Administration for inclusion in its Cook Inlet navigation chart.

In the company's March 3 request for reconsideration, Furie CEO and President John Hendrix said that on March 2 Furie provided "well location coordinates and casing height information" to NOAA for inclusion on the Cook Inlet navigation chart and said Furie would provide confirmation to AOGCC "that the information has been included in the NOAA database."

Site clearance

The company is requesting reconsideration on the site clearance issue, asking "for the appropriate weighting of risk, health and safety against leaving the three wells with structural casings 15 feet above the seafloor."

Hendrix said Furie agreed with comments from the Department of Natural Resources' Division of Oil and Gas, which supported the company's request to grant site clearance with the well casings 15 feet above the seabed floor.

"DNR, representing the State of Alaska as both the landowner and lessor of the mineral estate, carefully evaluated the risk to human safety versus the real impact of removing the casing stubs," Hendrix said.

Furie disagreed with comments from the Cook Inlet Regional Citizens Advisory Council and Cook Inletkeeper, which opposed leaving the stubs in place, citing concerns over navigational risks for marine vessels, the presence of large boulders in the vicinity, extreme tidal fluctuations, high currents and setting a precedent in Alaska for wells drilled from mobile offshore drilling units.

55-year record

In disagreeing with the commission's requirement that the stubs be removed, Furie referred to older wells which were drilled in the 1960s and had site clearance requirements waived — prior to enactment of current site clearance regulations.

Hendrix said the wells had similar configurations to the three Kitchen Lights unit wells at issue and, he said, for more than 55 years the wells "have posed no threat to navigation for marine vessels or have been influenced or damaged due to boulders, high currents, and extreme tidal fluctuations" — concerns cited by CIRCAC and Cook Inletkeeper.

"Furie is not willing to unnecessarily place human life at risk due to a technicality in regulation with on environmental impact," Hendrix said, adding that Furie agrees with DNR that this exception to the regulation "would not be precedent setting," calling it, instead, "just a sound management decision."

Safety issue

Hendrix discussed the safety issue of sending divers down to do the site clearance work and said Furie's motion for reconsideration "is based on the request for the appropriate weighting of risk, health, and safety against leaving the three wells with structural casings 15 feet above the seafloor."

"Placing people in one of the most hazardous environments without reasonable cause is not warranted. The conclusion by DNR, the SOA's resource owner are prudent and responsible. Furie should be allowed to leave the three wells with structural casing 15 feet above the seafloor and not place regulation ahead of human safety," he said.

In the December hearing Furie presented three cost estimates for cutting the casing: the most expensive, at almost $7 million, required mobilizing a jack-up rig; the other two options, at almost $4 million and just more than $2 million, required a barge and divers, with the price difference in whether the casing was cut at the mudline or 5 feet below the mudline.

Commission's decision

The commission said in its order that it would grant or refuse a reconsideration application in whole or part within 10 days and said failure to act within 10 days would constitute denial. A decision may be appealed to superior court.

In its March 1 order (see story in the March 7 issue of Petroleum News), the commission granted Furie's request to change the status of the wells to plugged and abandoned, but denied the waiver for site clearance, and said until site clearance is granted — which would require the casing stubs to be removed — the wells will be included on the list of Furie wells which require bonding.

In its conclusions the commission noted the six wells which were granted site clearance in the 1960s received that clearance "before the current offshore site clearance regulation was enacted."

The commission did not address the safety issue raised by Furie, but focused on the issue of setting a precedent:

"Granting site clearance for Furie's wells in their current condition, wells which were abandoned after the site clearance regulations were enacted in 1986, could set a precedent for future site clearances in the Cook Inlet and in all Alaskan waters," the commission said.

—KRISTEN NELSON

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WILLOW SCHEDULE

The company has already had to cancel plans for gravel mining and road construction during this winter's North Slope off-road season, because of a temporary court injunction against carrying out this work.

Court injunction

Sovereign Inupiat for a Living Arctic and several environmental organizations filed one of the cases, while some other environmental organizations filed the other case. Originally Judge Gleason turned down a request for an injunction banning Willow work in the field until the court cases are resolved. However, after the appellees appealed Gleason's injunction decision to the U.S. Court of Appeals for the 9th Circuit, Gleason issued an injunction, temporarily banning Willow gravel work pending a 9th Circuit response to the appeal. The 9th Circuit subsequently extended the injunction until the appeal is resolved, a decision that caused ConocoPhillips to cancel its gravel work for this year.

The various parties in the cases have since proposed to the District Court that, in the interests of minimizing litigation around the cases, the court should extend the current injunction to Dec. 1 of this year. If the court agrees to that arrangement, the plaintiffs in the cases will move to dismiss the pending 9th Circuit appeal, the plaintiffs told the District Court. Gleason subsequently approved the proposal and the parties in the cases have requested the 9th Circuit court to dismiss the appeal. Regardless of the injunction, Willow gravel work would presumably not be able to be started until tundra off-road travel is opened for the 2021-22 winter season.

—ALAN BAILEY

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NORTH FORK FOCUS

November.

"For the last 20 years we've been coming to Alaska," he said.

"There is a lot of bypassed gas here because the deposits weren't big enough" for the companies to bother with them, Gardes said. There also wasn't a market for it in Alaska. But eventually gas became the fuel of choice for heating buildings in much of Southcentral Alaska, while gas-fired generation became the favored source of electrical power.

"We think the future in the U.S. is gas. It burns 98% cleaner than oil and coal. It is a transformational resource," he said. ●

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OIL PRICES

rose $2.52 to $69.36, and WTI rose $2.26 to $65.05, before sliding lower on March 8 and March 9.

Prices had accelerated in early trading March 8 after an attack by Iran-backed Yemen Houthis the day before on Saudi oil facilities. The Saudi Energy Ministry confirmed a drone hit on a tank farm at Ras Tanura. But the Saudis said no property loss had occurred and prices fell in mid-morning trading, helped lower by strengthening of the U.S. dollar.

While the drone strike did not interrupt Saudi production, it may have an unintended effect on global oil supply going forward.

The attack could complicate efforts by Biden to revive the 2015 nuclear deal with Iran and lift Trump administration sanctions on Tehran's crude exports, the Washington Examiner said in a March 8 report.

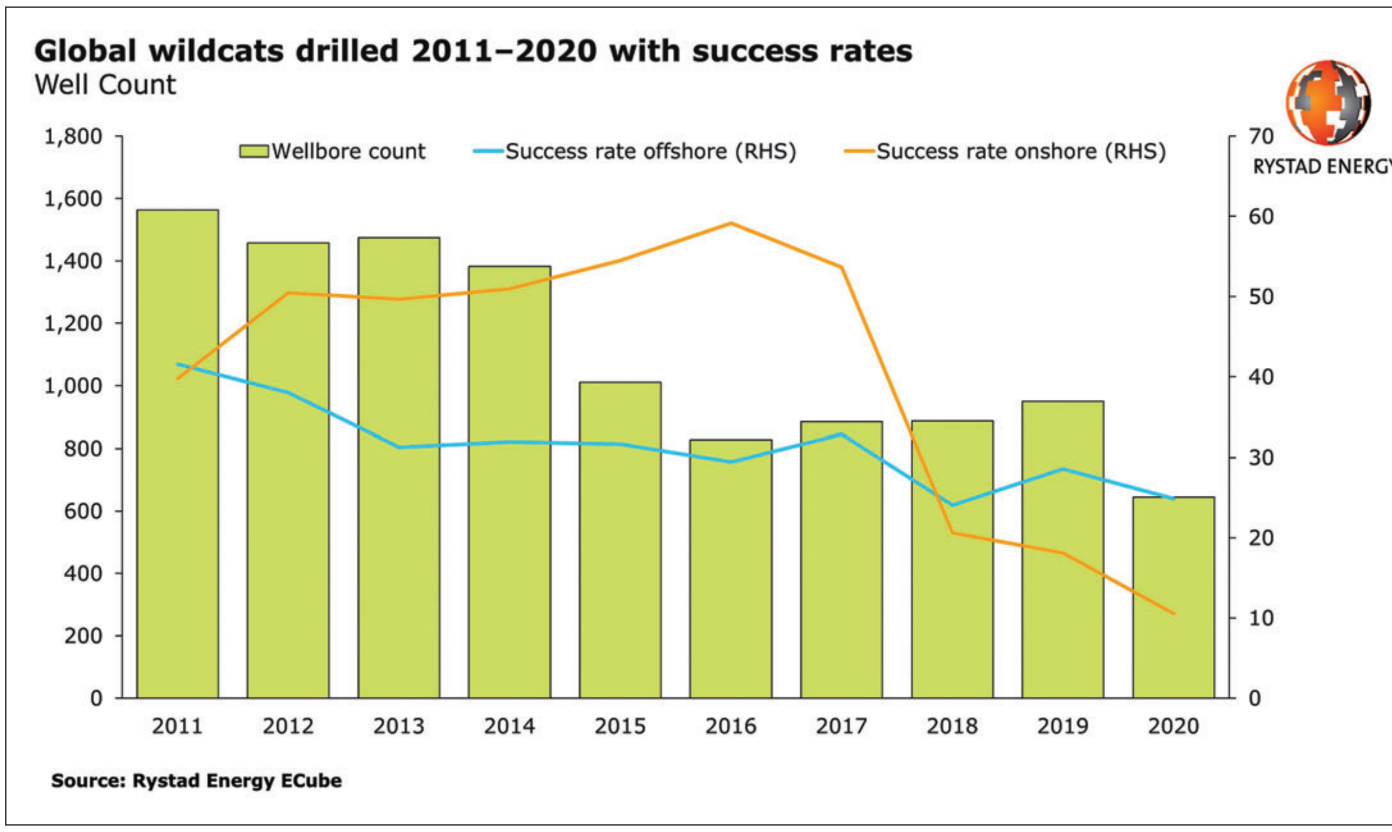
"The kingdom will take necessary and deterrent measures to protect its national resources," Foreign Minister Prince Faisal bin Farhan said. "The failed attempts to target the port of Ras Tanura do not only target the security of the economy and Saudi Arabia, they target the global economy and its oil supplies."

Although the week began with price corrections, ANS, WTI and Brent held closing prices above the level reached March 4 when OPEC+ shocked oil markets by forgoing a previously scheduled relaxation of its production cuts.

At the 14th Meeting of OPEC and non-OPEC Ministers March 4, OPEC+ ministers approved a continuation of March production levels into April; however, Russia was allowed to increase production by 130,000 bpd and Kazakhstan was allowed to increase production by 20,000 bpd, "due to continued seasonal consumption patterns," OPEC said in a March 4 release.

Since the signing of a Declaration of Cooperation to curtail production at the 10th OPEC and non-OPEC Ministerial Meeting in April 2020, "overall conformity with the original decision was 103 per cent," OPEC said, adding that since the April meeting, OPEC+ had withheld 2.3 billion barrels of oil by end of January, "accelerating the oil market rebalancing."

The group will decide the level of May production cuts at its 15th OPEC and non-OPEC Ministerial Meeting, to be held April 1.



Onshore success rate dips

The success rate of global conventional oil and gas exploration has declined in recent years, most notably the success of onshore wildcat wells, according to a March 5 Rystad Energy report.

In 2020, the success rate of onshore drilled wildcats hit an all-time-low of 10.6%, declining for a fourth year in a row.

During the first half of the last decade, operators had success rates in wildcat drilling of between 40-60% for onshore and 30-40% for offshore, Rystad said. Both onshore and offshore wells have had a decline in success rates in recent years but for onshore the drop since 2016 — when explorers recorded nearly 60% success with wildcats — has been particularly alarming.

Offshore, the success rate has seen mild fluctuations during this decade and the 2020 score ended at 24.8%, down from 28.6% in 2019 but slightly higher than the 24.1% recorded in 2018, the consultancy said.

"The lack of availability of easily exploitable prospects, combined with dying exploration activity in once rich onshore areas such as the Middle East, have led to the decline in the onshore success ratio," said Palzor Shenga, vice president at Rystad's upstream team. "Most of the easily mappable structural prospects with shallow reservoirs have already been thoroughly explored, leaving wildcatters to struggle primarily with technically challenging prospects."

Rystad said it does not foresee a significant improvement in the onshore success ratio soon and much more activity will be focused on offshore areas, where prospects are associated with higher unrisked resources.

In 2021, Rystad expects 70% of high-impact wildcats to target deepwater and ultra-deepwater plays, 17% targeting offshore shelf areas, and the remaining 13% targeting onshore.

"This indicates that the high-risk deep and ultra-deep plays continue to garner interest despite the decrease in exploration spending," Rystad said.

In 2020 474 onshore wildcats were drilled, but Rystad projects only 253 in 2021 and 270 in 2022, never exceeding 300 wells per year through 2025. The number of offshore wildcats, however, is forecast at 217 in 2021 and 300 in 2022, up from 180 in 2020. ●

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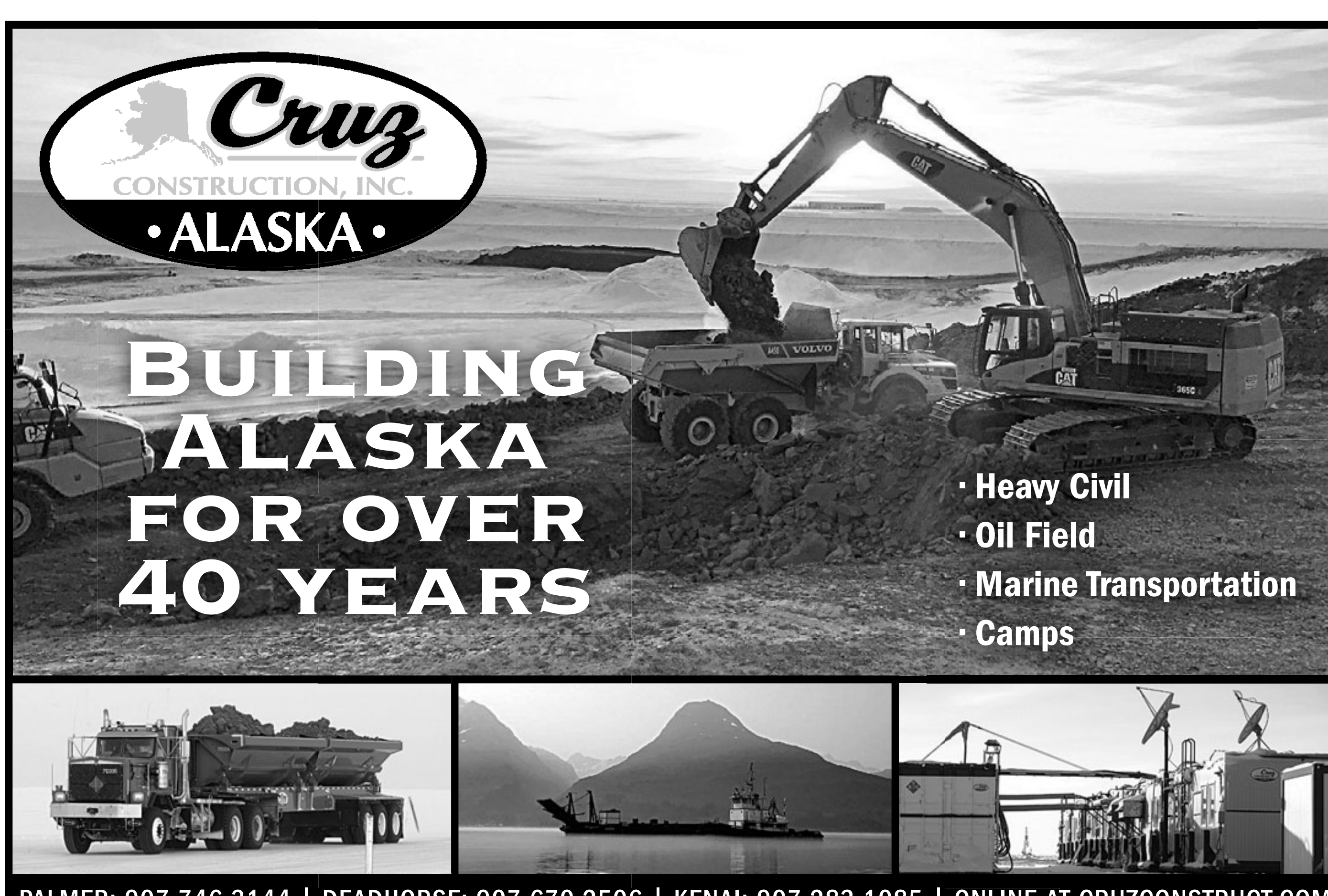

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approximately one week.

"The well will then be deepened through the target horizons in the Nanushuk formation to a maximum total depth of 6,000 feet," the company said. "Logging while drilling and mudlogging will provide initial indications as to the prospectivity of the well during this part of the operation, which is expected take three to five days."

Next, "a sophisticated wireline logging suite" will be run, including sidewall cores and downhole sampling, which will take three to five days.

"If the results from the wireline logging are encouraging, then the well will be completed with casing and a flow test conducted," the company said.

ERIK OPSTAD

"As part of a standard cost review, 88E's share of the cost of Merlin 1 has been revised to US$4m (increased from US$1.4m). The main contributing factors to the cost increase are delays associated with the Executive Order regarding the issuance of the Permit to Drill; costs associated with shutdown and re-start whilst clarification was attained regarding the Executive Order; delays associated with cold weather and the subsequent knock on to mobilization costs as a result of expediting activities to meet the operational timetable. The company's current cash position is US$13m, which more than funds its share of the drilling of Merlin 1 and the company's other planned activities," 88 Energy said.

In its 2020 annual report, 88 Energy's non-executive Chairman Michael Evans said March 9 that Merlin 1 is "targeting 645 million barrels of gross mean prospective resource" and Harrier 1 would target a gross mean prospective resource of 417 million barrels.

In the chairman's letter, Evans praised Alaska's North Slope, saying its source rocks "have been

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> *—88 Energy March 10 update*

described as unbelievably rich and prolific, having generated and expulsed about 1.5 trillion barrels of oil. Yet only a small fraction of that 1.5 trillion barrels has been found, leaving vast potential remaining to be discovered."

"Access to existing infrastructure, a very supportive and stable state government and significant exploration upside," are three of the things 88 Energy likes about the state, Evans said, noting 88 Energy operates 444,517 net acres on the North Slope.

"Our prospective land holding is now of a size one would normally associate with the big end of town and provides continued scope to attract partners," he said.

12 states sue Biden on climate change order

A COALITION OF 12 STATES is suing President Joe Biden's administration over a climate change executive order that they say has the potential to have serious economic impacts across the country through the expansion of federal regulatory power.

The lawsuit, which is being led by Missouri Attorney General Eric Schmitt, was filed on March 8 in federal court in the Eastern District of Missouri.

State attorneys general from Arkansas, Arizona, Indiana, Kansas, Montana, Nebraska, Ohio, Oklahoma, South Carolina, Tennessee and Utah also joined the action. As of 4 p.m., March 10 there was no response from a March 9 query as to whether the State of Alaska would be joining the legal action.

The lawsuit claims Biden's Executive Order 13990, dubbed "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" and signed hours after his inauguration on Jan. 20, does not have the authority to establish amounts for the "social cost of greenhouse gases" to be used in federal regulations.

According to a March 8 report in The Epoch Times, the lawsuit argues that "Biden's order could inflict trillions of dollars of damage to the U.S. economy, while saying that the executive order threatens the Constitution's separation of powers doctrine."

"In practice, this enormous figure will be used to justify an equally enormous expansion of federal regulatory power that will intrude into every aspect of Americans' lives — from their cars, to their refrigerators and homes, to their grocery and electric bills," the lawsuit reads.

According to the White House, Biden's Jan. 20 order is, among other things, designed to "conserve our national treasures and monuments."

"Where the federal government has failed to meet that commitment in the past, it must advance environmental justice," the order said.

The order directs all federal agencies and departments to review and "take action" to address the Trump administration's climate-related executive orders, the Times reported.

Alaska Department of Natural Resources Commissioner Corri Feige expressed concern about the potential impacts of EO 13990 on Alaska's oil and gas industry when addressing the Senate Resources Committee on Jan. 27 (see story in the Feb. 14 issue of Petroleum News titled "Sucking all the air out").

One directive in the order is to listen to "the science," Feige noted. "Largely those policy initiatives in the Biden administration are focused on climate change and climate crisis," she told committee members.

"For me, I think where we're going to see the greatest amount of discussion — and this is certainly something that the state is going to be paying extremely close attention to — is this discussion of listening to the science. The question is, who gets to decide what is the science, and what science is robust enough?"

Feige said a lot of questions exist around climate change science.

—KAY CASHMAN

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