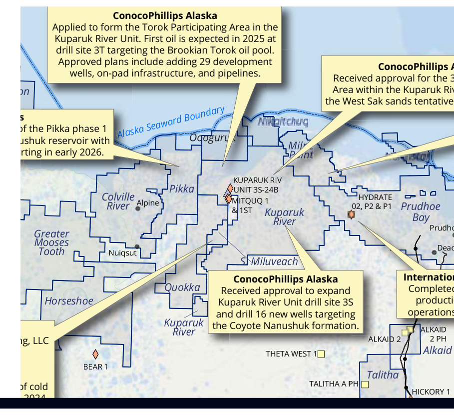
Petroleum news



page 6 DNR posts latest oil and gas activity maps for North Slope and Cook Inlet

Vol. 29, No. 4 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* Week of January 28, 2024 • $2.50

AOGCC hears neighbor concerns about Hilcorp's Cottonfield well

Hilcorp Alaska's proposed Cottonfield 6 exploration well was a focus of concerns from those living in the area, as the Alaska Oil and Gas Conservation Commission held a hearing on the company's request for a spacing exception Jan. 18 in Anchorage.

The company has drilled a number of stratigraphic test wells at the prospect east of Cosmopolitan on the southern Kenai Peninsula, and now plans its first exploration well at the prospect. Because there are other owners within 1,500 feet of the proposed well, the commission needs to approve a spacing exception before it can issue a drilling permit, to protect both adjacent landowners and underground drinking water.

As for the amount of public interest and the types of concerns raised about Kenai Peninsula drilling, the commission noted in its notice of the public hearing that, "As a general matter, AOGCC does not have extensive authority over surface impacts such as noise, emissions, or construction."

AOGCC Chair Brett Huber said the hearing allowed the commission and Hilcorp to hear the public's concerns and gets those concerns on the public record and available to other agencies.

The spacing regulations "protect the oil and gas rights of

see **COTTONFIELD WELL** *page 12*

Hilcorp to do more water, gas injection at its Northstar unit

In its Jan. 19 approval of Hilcorp Alaska's 20th plan of development for Northstar, the Alaska Department of Natural Resources' Division of Oil and Gas said the plan protects the public interest by preventing waste through continued production from existing wells, maximizing water injection in the Kuparuk reservoir for pressure maintenance and increasing Ivishak formation gas injection.

In the 19th POD Hilcorp had committed to a workover on the NS-16A well, work which was successfully performed, the division said, along with five additional wellwork and workover projects — recompleting wells, adding perforations or converting wells from producers to injectors. Hilcorp completed the ground refrigeration expansion for a total of 156 heat pipes in service and continues to evaluate coil tubing drilling at Northstar.

There are three participating areas at Northstar, representing three separate oil accumulations: Ivishak sands in the Northstar PA and Fido PA, and Kuparuk sands in the Hooligan PA.

see **NORTHSTAR INJECTION** *page 11*

Chevron unloads Alberta assets, has Duvernay gas play up for sale

Chevron is stepping up the streamlining of its Canadian assets by putting its natural gas business in northern Alberta's Duvernay natural gas play up for sale in a deal it expects will generate C$1.2 billion.

The assets, which yield about 40,000 barrels per day of oil and gas from almost 1,000 square kilometers in the Duvernay fields, could fetch US$900 million according to Houston-based firm Energy Advisors Group.

The transaction is part of Chevron's plans to offer for sale at least US$10 billion in assets over the next 4 years after a transaction is completed with Hess Corp. PDC Energy and Noble Energy that will significantly increase its oil and gas output.

"We have a strong position and are proud of our performance in the Duvernay," a company spokesman told Reuters. "The business holds significant value in both our current production as well as potential growth opportunities which we expect to be attractive to other companies with complementary portfolios."

see **CHEVRON ASSETS** *page 8*

UTILITIES

Railbelt low carbon

ACEP study evaluates options for renewable power generation in the region

By ALAN BAILEY
For Petroleum News

The Alaska Center for Energy and Power at the University of Alaska, Fairbanks, has published the results of a study into possible strategies for decarbonizing the Alaska Railbelt electricity generation grid by 2050. Rather than developing an actual plan for decarbonization, the purpose of the study was to evaluate the technical viability and potential cost of decarbonization scenarios, to inform the Alaska public and decision makers on the cost and power supply reliability issues associated with decarbonization.

On Jan. 19 members of the project team presented the findings of the study to the Alaska Senate Resources Committee.

> *The team found that some level of gas-fueled power generation would be needed to ensure adequate power supply stability and reliability in all of the scenarios other than the scenario involving nuclear power.*

A two-year project

Phylicia Cicilio, research assistant professor in power systems engineering, told the committee that the project took 2 years to complete and consisted of

see **ACEP STUDY** *page 11*

FINANCE & ECONOMY

ANS pops on US draw

Inventories down 9.2 million barrels as arctic weather chills production

By STEVE SUTHERLIN
Petroleum News

Alaska North Slope crude pressed higher into the $80s Jan. 24, gaining 70 cents to close at $80.79 per barrel. West Texas Intermediate gained 72 cents on the day to close at $75.09 and Brent added 49 cents to close at $80.04.

Prices were supported by a massive 9.2 million barrel drawdown of U.S. commercial crude oil inventories for the week ending Jan. 19, revealed by the U.S. Energy Information Administration in its Jan. 24 status report. The drop dwarfed the 2.2 million barrel draw analysts forecast in a Reuters poll.

Inventories were left at 420.7 million barrels, some 5% below the five-year average for the time of year.

> *Analysts with S&P Global Commodity Insights see a new round of OPEC+ cuts in the first quarter — the fifth since October 2022 — to counteract rising non-OPEC supply.*

Total motor gasoline inventories jumped by 4.9 million barrels for the period to 253 million barrels, 1% above the five-year average for the time of year. The jump likely reflected a slowdown in driving due to blustery arctic weather casting a broad sweep across the nation.

see **OIL PRICES** *page 9*

EXPLORATION & PRODUCITON

Cook Inlet gas, part 1 of 2

DNR hosts Lunch & Learn about importance of Cook Inlet gas to Alaskans

By KAY CASHMAN
Petroleum News

1 2 SERIES

DEREK NOTTINGHAM

On Jan. 17, a legislative hearing was sponsored by Alaska Sen. Cathy Giessel and Rep. Tom McKay in order to host a Lunch & Learn session about the Cook Inlet hydrocarbon basin by two key members of the Alaska Department of Natural Resources' Division of Oil and Gas.

Division Director Derek Nottingham and commercial analyst for oil and gas Weston Nash made the presentation.

Part one of this story will mainly cover what was said by Nottingham.

"We want to convey to you how important Cook Inlet gas is to the energy providers of the state and how important the gas supply is going into the future," Nottingham said in his introduction.

The planned agenda, he said, is as follows:

—Why is CI gas important

—Cook Inlet overview, geology and production history

—DNR's 2002 Cook Inlet gas forecast

—DNR's and the Division's role in Cook Inlet

The first of several slides, Why Is Cook Inlet

see **INLET GAS** *page 10*

● EXPLORATION & PRODUCTION

Baker Hughes US rig count up by 1 to 620

By KRISTEN NELSON
Petroleum News

The Baker Hughes' U.S. rotary drilling rig count was 620 for the week ending Jan. 19, up by one rig from 619 the previous week, and down by 151 from 771 a year ago. The rig count increased four of the last eight weeks, but the overall loss of nine rigs over the period compared to a gain of seven continues a downward trend dominant since the beginning of May.

A drop of 17 to 731 on May 12, 2023, was the steepest weekly drop since June of 2020, during the first year of the COVID-19 pandemic, when the count also dropped by 17 to 284 on June 5, following drops as steep as 73 rigs in one week in April. The count continued down to 251 at the end of July 2020 before beginning a slow climb upward.

As 2023 reached its end, the count hovered in the 620s for more than a month with the Dec. 29 count of 622 down from a high of 775 on Jan. 13, 2023. The high for 2022 was 784 rigs at the beginning of December.

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

Baker Hughes shows Alaska with 10 rotary rigs active Jan. 19, unchanged from the previous week and up by two from a year ago when the count was eight.

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 prior to the COVID-19 pandemic, where it remained through mid-March of that year 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 Jan. 19 count includes 497 rigs targeting oil, down by two from the previous week and down 116 from 613 a year ago, with 120 rigs targeting natural gas, up three from the previous week and down 36 from 156 a year ago, and three miscellaneous rigs, unchanged from the previous week and up one from a year ago.

Forty-eight of the rigs reported Jan. 19 were drilling directional wells, 560 were drilling horizontal wells and 12 were drilling vertical wells.

Alaska rig count unchanged

Pennsylvania (21) was up by two rigs from the previous week.

Kansas (2), Louisiana (43) and New Mexico (98) were each up by one rig.

Texas (305) was down three rigs week over week and Oklahoma (42) was down a single rig.

Rig counts in other states were unchanged from the previous week: Alaska (10), California (5), Colorado (16), North Dakota (33), Ohio (13), Utah (12), West Virginia (8) and Wyoming (10).

Baker Hughes shows Alaska with 10 rotary rigs active Jan. 19, unchanged from the previous week and up by two from a year ago when the count was eight. Nine of the Alaska rigs were onshore, unchanged from the previous week, with one rig working offshore, also unchanged from the previous week.

The rig count in the Permian, the most active basin in the country, was down by two from the previous week at 307 and down by 47 from 354 a year ago. ●

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contents

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● GOVERNMENT

AOGCC hearing on CIE Badami well permit

Company has been discussing with commission staff its request to drill B1-33 exploration well using alternate pressure gradient

By KRISTEN NELSON
Petroleum News

Cook Inlet Energy, a Glacier Oil and Gas company, operates the Badami unit on the North Slope under a subsidiary, Savant Alaska. CIE met with Alaska Oil and Gas Conservation Commission staff Oct. 5 for a pre-submittal meeting on permits for the Badami B1-33 and B1-33PH wells and submitted the permit applications Oct. 16.

It's been back and forth ever since, with the company targeting a Feb. 1 spud date and still no permit.

In a Jan. 23 public hearing, AOGCC staff discussed the issue, followed by a presentation by CIE.

It's technical, with CIE proposing to use what the agency calls an alternate pressure gradient for calculating MASP, maximum anticipated surface pressure, to be encountered when drilling a well.

CIE is using Doyon 19 for the wells. That rig supports a MASP of 5,000 pounds per square inch; to meet AOGCC's requirement would require supplementing equipment on the rig to meet the 10,000 psi requirement, which, CIE said, cannot be done within the rig walls, but would require additional equipment which would be outside the rig walls, creating a concern about ice plugs.

At the Jan. 23 hearing, CIE said Doyon 19 was staging to travel on the ice road to meet a planned Feb. 1 spud date.

AOGCC's Mel Rixse, a senior petroleum engineer, said the commission didn't accept CIE's justification for the alternate pressure gradient.

He noted that there was a 2008 regulation change regarding the issue of pressure gradients, a change supported by the Alaska Oil and Gas Association.

During the public comment period at the end of the hearing, Rep. Tom McKay, chair of the Alaska House Resources Committee, called in to comment and offered to write emergency regulations to alleviate the problem.

CIE argues consistency

CIE said in its presentation that it was requesting that AOGCC approve "a more accurate means of determining the maximum potential surface pressure." CIE personnel told the commission that its permit application was consistent with a previously drilled Badami well and said that at earlier meetings with AOGCC staff it had presented data from five previous penetrations at Badami.

The company presented a statement from Petrophysical Resources Alaska, PRA, which did a third-party review of CIE's data.

"CIE integrated sound geologic assumptions and followed accepted petroleum engineering principles and practices to calculate its MASP for the B1-33 well. Based on a review of the data, assumptions and information used by CIE, CIE's request for use of a different pressure gradient that provides a more accurate means of determining the maximum potential surface pressure is justified for the B1-33 well," PRA said in a statement provided to the commission by CIE.

AOGCC Chair Brett Huber said at the beginning of the hearing that no public comments were received and that completing the order would be expedited.

From Badami Main Pad

The Alaska Department of Natural Resources, Division of Oil and Gas approved a unit plan of operations amendment for the B1-33 well Dec. 19, authorizing work on state lands.

The approval said the Kennicott B1-33 exploration well would be drilled with Doyon 19 or a similar rig on the Badami Main Pad.

A 26.6-mile ice road was planned from the Endicott/Duck Island Unit Road to the Badami Main Pad, work authorized separately, the division said.

A temporary 50-main camp on the Badami Main Pad will support operations.

The surface hole is on ADL 365533 and the bottomhole on ADL 367011. ●

Contact Kristen Nelson at knelson@petroleumnews.com

LAND & LEASING

State OKs Prudhoe Bay assignments

The Alaska Department of Natural Resources' Division of Oil and Gas has approved assignments for eleven Prudhoe Bay unit leases. The division said in the Jan. 17 decisions that assigning interests to six decimal places allows identical working owner interest across all Prudhoe Bay unit leases. The same eleven leases are included in the three decisions.

Assignments include transferring 36.402687% working interest from Hilcorp North Slope to ExxonMobil Alaska Production with Hilcorp North Slope retaining 27.520567% interest.

The division said Hilcorp requested the assignment approvals Jan. 10.

For the same eleven leases, the division also approved transferring 36.076746% working interest ownership to ConocoPhillips Alaska with Hilcorp North Slope retaining 63.923254%.

In a third decision the division approved a transfer of 1.160000% working interest from Hilcorp North Slope to Chevron U.S.A. with Hilcorp retaining 29.360567%.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

Injection well approved for POD inclusion

Activities on a Beluga River unit injection well, BRU 232-09, have been approved for inclusion in the unit plan of operations for the BRU. No surface expansion or alteration to well infrastructure will occur, the Alaska Department of Natural Resources' Division of Oil and Gas said in a Jan. 17 lease plan of operations amendment decision.

The well was drilled by Chevron U.S.A. in 1985, the division said, and converted to a Class I injection well by ConocoPhillips Alaska in 2009, before being transferred to Hilcorp Alaska in 2016.

Hilcorp operates the Beluga River unit; Chugach Electric Association is the majority working interest owner.

The well is currently used as a Class I injection well, primarily for BRU waste disposal, but there is also third-party waste disposal using the well, mostly from the Lewis River unit and not part of ongoing operations but only on a project-specific basis.

The division said it has determined that the majority of waste injected into BRU 232-09 is from BRU operations, with de minimus quantities of third-party waste, and therefore it is appropriate to incorporate the well into the BRU plan of operations.

The surface location of BRU 232-09 is in the federally managed portion of BRU on the DW-1 Pad about 1 mile southwest of the Beluga Airport, with surface ownership by the Kenai Peninsula Borough and subsurface ownership by the Bureau of Land Management.

The bottomhole location is offshore on state of Alaska surface and subsurface, in ADL 17592.

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● THIS MONTH IN HISTORY

Geologist's dream, investor's nightmare

20 years ago this month: North Slope basin one of most expensive anywhere, Mike Dunn says, increasing minimum economic size

Editor's note: This story appeared in the Jan. 25, 2004, issue of Petroleum News.

By **KRISTEN NELSON**
Petroleum News

Why are there so few companies exploring Alaska's North Slope, a basin with recognized world-class hydrocarbon potential? The answer is cost: "The North Slope basin is the most expensive onshore basin in the world. … And it may even be one of the most expensive basins in the world, including offshore basins," Mike Dunn told the Anchorage chapter of the International Association for Energy Economics Jan. 20.

Dunn, vice president of New Tech Engineering, an Anchorage, Alaska-based consulting firm, was talking about a problem he confronted as a consultant working with companies interested in coming to Alaska: "The minimum economic size on the North Slope: why is it so large and what can we do to reduce it?"

Minimum economic size is a question addressed by oil companies of all sizes: It's not, can I find oil in this basin, it's if I find oil can I make money producing it?

Over the last 5 or 10 years, Dunn said, most companies have adopted a methodology that lets them look at a combination of factors — geologic risk, reserve size, development costs and cash flow models — and then determine the minimum size field needed to make money. The result, minimum economic size, can be compared with opportunities in basins worldwide.

Dunn said when he did the analysis for independents interested in the North Slope "sticker shock" was the typical reaction.

Sticker shock

Dunn said prospects 50 miles from North Slope infrastructure would have to be about 360 million barrels to break even, and when he explains that to companies looking at Alaska, the reaction is not positive. Companies who can find 100 million barrels in the Gulf of Mexico in 8,000 feet of water and make money aren't likely to be interested in a basin where they would have to find 360 million barrels just to break even.

Some companies do look harder, he said, and question whether you really have to spend a billion dollars for a facility and gravel and infield pipelines for 120,000 barrels a day. They start looking at what has been done in Canada or in Russia and thinking it can be done cheaper on the North Slope.

Rigs are another issue. Dunn said companies compare $110,000 a day "as the spread day-rate on a drilling rig in a land-rig operation" on the North Slope with $100,000 a day for a jack up rig in the Gulf of Mexico with boat and helicopter support: another unfavorable comparison.

There is another wrinkle to this.

If you have to find 360 million barrels to break even, that's about a 1 in 20 chance of making a commercial discovery, Dunn said, based on how the U.S. Geological Survey estimates the numbers and sizes of fields in basins. There are just limited numbers of fields that large.

Why the cost?

There are legitimate reasons for high costs on the North Slope, he said. It's a long way from markets, it's a long way from major population centers and the climate is very harsh. But Dunn said he believes some of the reasons for high costs are based on the culture which grew up on the North Slope when oil was discovered — billions of barrels of oil in a single field.

Prudhoe Bay, he said was "the best thing and the worst thing to happen to the North Slope."

It established infrastructure, and only a field of that size could have justified the facilities at Prudhoe and the trans-Alaska pipeline.

But it also created a culture where people said: "money is no object; this is Prudhoe Bay."

There are things you could afford to do at Prudhoe Bay, because of its size, that you can't afford to do at the types of fields being looked at for development now, Dunn said.

Can any of that be changed?

Is Alaska that different?

Dunn said another part of the "cultural" side of the cost equation is the notion that Alaska is different, i.e. just more expensive.

That was true 30 years ago. "Alaska was different," he said. The North Slope was the first Arctic basin developed and a lot of technology had to be developed specifically for Prudhoe Bay.

But today there are Arctic developments in both Canada and Russia, and Alaska is not as different as it once was.

Dunn said he's done a lot of benchmarking of Alaska costs to costs in Canada. "It is surprising how much less expensive those developments are" in Canada, he said. And part of the reason for the difference is that the Canadian Arctic industry started with small gas fields and "they've just had to figure out cheaper ways to develop these fields."

Opportunities to reduce costs?

What opportunities exist to reduce costs?

Dunn said an Energy Information Administration study comparing drilling costs in Alaska with those in the Lower 48 found it would cost about $2.5-$3 million to drill a 10,000 foot well on the North Slope, compared with about $750,000 to drill a 10,000 foot well in south Texas. And, Dunn said, drilling on the North Slope is generally faster.

So, he asked, how much of the cost difference is due to the harsh climate and the distance from infrastructure? And how much is due to the way things are done. "I don't know exactly," Dunn said, "but I do think there's some opportunity to reduce the costs on the North Slope."

see **HISTORY** page 5

continued from page 4

HISTORY

Typically independents follow majors into basins, he said, and independents “might take a more hands-on approach” to cost reduction and work the facilities costs a little harder and work the drilling costs a little harder.

“Independents have traditionally been better at cost reduction and cost control,” Dunn said, it’s one of their “core competencies” because they are developing smaller fields than those developed by the majors and have to figure out ways to reduce costs — or they go out of business.

What if costs could be reduced?

Dunn said that if you plug cost reductions into the formulas used to calculate minimum economic size the changes can be dramatic.

The trans-Alaska oil pipeline tariff, for instance. If capital costs came out when that tariff has a re-opener in 2009, and the tariff dropped by $1.25 a barrel that takes about 60 million barrels out of the 360 million minimum economic field size. Dunn used a one-sixth royalty rate, and if you drop that to one-eighth, that takes the minimum barrel size down to about 270 million barrels.

And what if there were some way to reduce the marine transportation cost, now driven up by the requirement to use Jones Act tankers? What if moving ANS crude to the West Coast was comparable to moving oil from Venezuela to the Gulf of Mexico, a reduction of 50 cents a barrel?

The construction cost of facilities is a very large item.

Dunn said he looked at tax rolls and found that Alpine and Northstar were considerably more expensive than Badami when Badami costs were factored to handle more barrels, using a scaling factor used by chemical engineers. If facilities could be built on a Badami model, that would cut the cost substantially, and bring the minimum field size down to a little more than 150 million barrels.

And what if there was a better rig, or a better way to drill North Slope wells, and that cost could come down to $80,000 a day, and then, given that independents are known for cutting costs, on top of all of this the independent finds a way to cut another 20%?

Stars in alignment

Dunn acknowledged that in his example — which cuts the minimum economic size down to about 100 million barrels — that “all the stars are lined up.” This is, he said, the best you could expect.

“You’ve gotten some tariff reduction, marine costs are a little lower, you’ve got a one-eighth royalty, you’ve captured all of the lessons learned at Badami, you’ve worked the drilling rig and the drilling support real hard — and then you’ve got another 20% cost reduction on top of that.”

Is it just impossible?

Dunn cited an example from the Norwegian sector of the North Sea, where development also started with a large expensive field — Ekofisk — and where, in the early 1990s, the Norwegian government began hearing that it was too expensive to operate, and companies said they would look elsewhere to invest.

Government officials, operators, service companies and drilling contractors got together and looked at the costs, and they took 70% out of the capital cost between 1993 and 1998. Dunn said he didn’t know how differences in such things as water depth and field size were handled in this comparison, “but the point is that they thought there was some potential for cost reduction and they worked it and sure enough, they delivered on it.”

JUDY PATRICK

A CATCO rolligon in blowing snow on Alaska’s North Slope. Photo taken during the day, mid-winter.

What if the minimum was 100 million barrels?

So what if 100 million barrels was the economic minimum, how does that change things?

Dunn said it changes the chance for success from 1 in 20 at the 360 million barrel size to 1 in 7 because there is a lot more potential for finding 100 million barrel fields than there is for finding 360 million barrel fields. And when more fields are developed, more infrastructure is built — making even smaller accumulations economic.

And what if there is no way to reduce costs?

Well, geologists love the North Slope basin — they know there is a lot of potential — but investors hate it, he said. “It’s not about the resource, it’s about reserves — and we need economic reserves. The minimum economic size has got to be reduced, or this basin will die,” Dunn said. “This basin is not competitive with other basins.”

And it is the costs that define minimum economic size: development cost, operating cost, transportation cost, royalty cost, tax cost, he said. If those costs can be reduced, if the minimum economic size were 100 million barrels, the value of the basin increases because there are more fields you can develop, and as infrastructure develops, smaller fields become economic.

“What’s the value of that in terms of billions of billions of dollars to the state’s economy, to the oil companies, if you can affect the minimum size?” Dunn asked. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

DNR posts new Slope, Cook Inlet activity maps

By KAY CASHMAN

Petroleum News

The latest North Slope and Cook Inlet oil and gas activity maps were recently posted on the Alaska Department of Natural Resources' Division of Oil and Gas website (see maps in pdf and print versions of this story).

Both maps are dated December 2023 but were released in January 2024 in legislative hearings.

The last time the division released activity maps was in June 2023.

Both the December 2023 Cook Inlet and North Slope maps are very detailed, including such things as unit boundaries, prospects, planned early 2024 exploration wells, seismic programs and releases, development projects, and many geographical elements.

Both maps also include the locations of all exploration wells drilled in 2021, 2022 and 2023 on the North Slope and in the Cook Inlet basin.

North Slope

Per the North Slope activity map, active oil and gas companies on the North Slope include 88 Energy/Accumulate Energy, Balcony, ConocoPhillips Alaska, Finnex, Great Bear, Hilcorp, Santos and Savant.

The activity described on the North Slope map includes state of Alaska land, federal land, including the National Petroleum Reserve-Alaska and disputed lands, and Native Alaska lands, as well as projects on combined land.

Some of the December 2023 North Slope map's highlights include the following:

• Santos drilled five wells as part of the Pikka phase 1 project targeting the Nanushuk reservoir with expected oil production starting in early 2026.

•AIDEA closed on sale of Mustang field to Finnex Operating, LLC on Oct. 27, 2023.

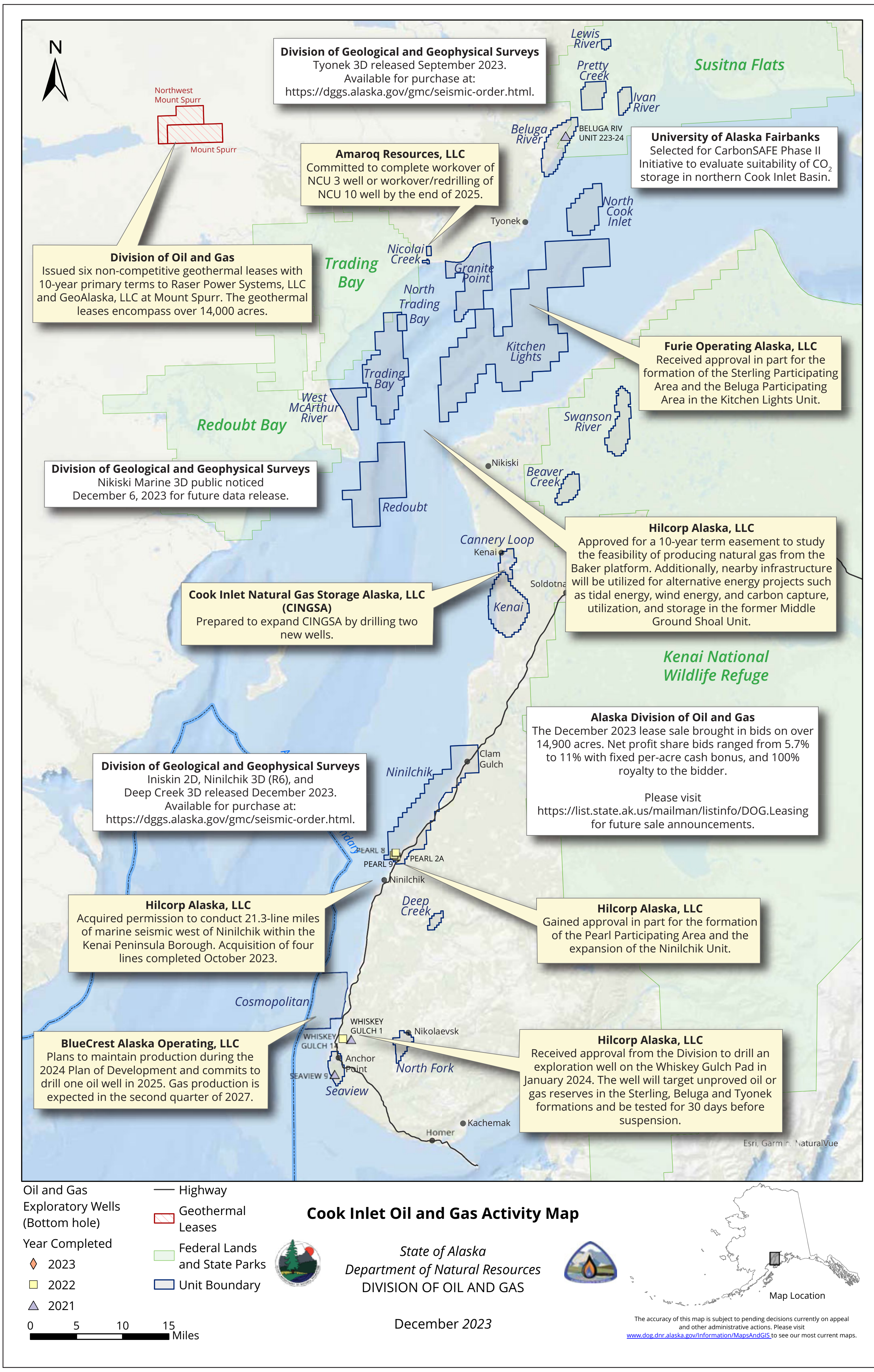
•Mustang Holding LLC received approval for 10th POD to transition out of cold shut-down and target resumed production by late 2024.

•ConocoPhillips Alaska received approval to expand Kuparuk River Unit drill site 3S and drill 16 new wells targeting the Coyote Nanushuk formation.

•Savant Alaska LLC received approval from the division to drill Kennicott B1-33 exploration well on the Badami Main Pad beginning Jan. 20, 2024.

•Balcony Natural Resources Inc. received approval for the Grey Owl Unit. The 5-year plan includes drilling at least one exploration appraisal well during the winter of 2026-27.

•Lagniappe Alaska LLC received approval from the division to drill King Street-1, Voodoo-1, and Sockeye-1 exploration wells beginning Jan. 1, 2024, as part of their two-year, six-well exploration program.



•ConocoPhillips Alaska announced final investment decision approving the Willow project and funding for construction needed to reach first oil.

•International Hydrates Test Project completed two monitoring and two production wells. Long term test operations began Oct. 24, 2023.

•Accumulate Energy Alaska Inc. received approval to frac and flow test the Hickory 1 well in the Toolik River Unit beginning January 2024.

•Division of Geological and Geophysical Surveys released Umiat 3D reprocessing in December 2023. Available for purchase at: https://dggs.alaska.gov/gmc/seismic-order.html.

Cook Inlet

Following are a few of the highlights in the December 2023 Cook Inlet map:

•Division of Geological and Geophysical Surveys released Iniskin 2D, Ninilchik 3D (R6), and Deep Creek 3D December 2023. Available for purchase at: https://dggs.alaska.gov/gmc/seismic-order.html.

•Hilcorp Alaska LLC received approval from the division to drill an exploration well on the Whiskey Gulch Pad in January 2024. The well will target unproved oil or gas reserves in the Sterling, Beluga and Tyonek formations and be tested for 30 days before suspension.

•Furie Operating Alaska LLC received approval in part for the formation of the Sterling Participating Area and the Beluga Participating Area in the Kitchen Lights Unit.

•BlueCrest Alaska Operating LLC plans to maintain production during the 2024 plan of development and commits to drill one oil well in 2025. Gas production is expected in the second quarter of 2027.

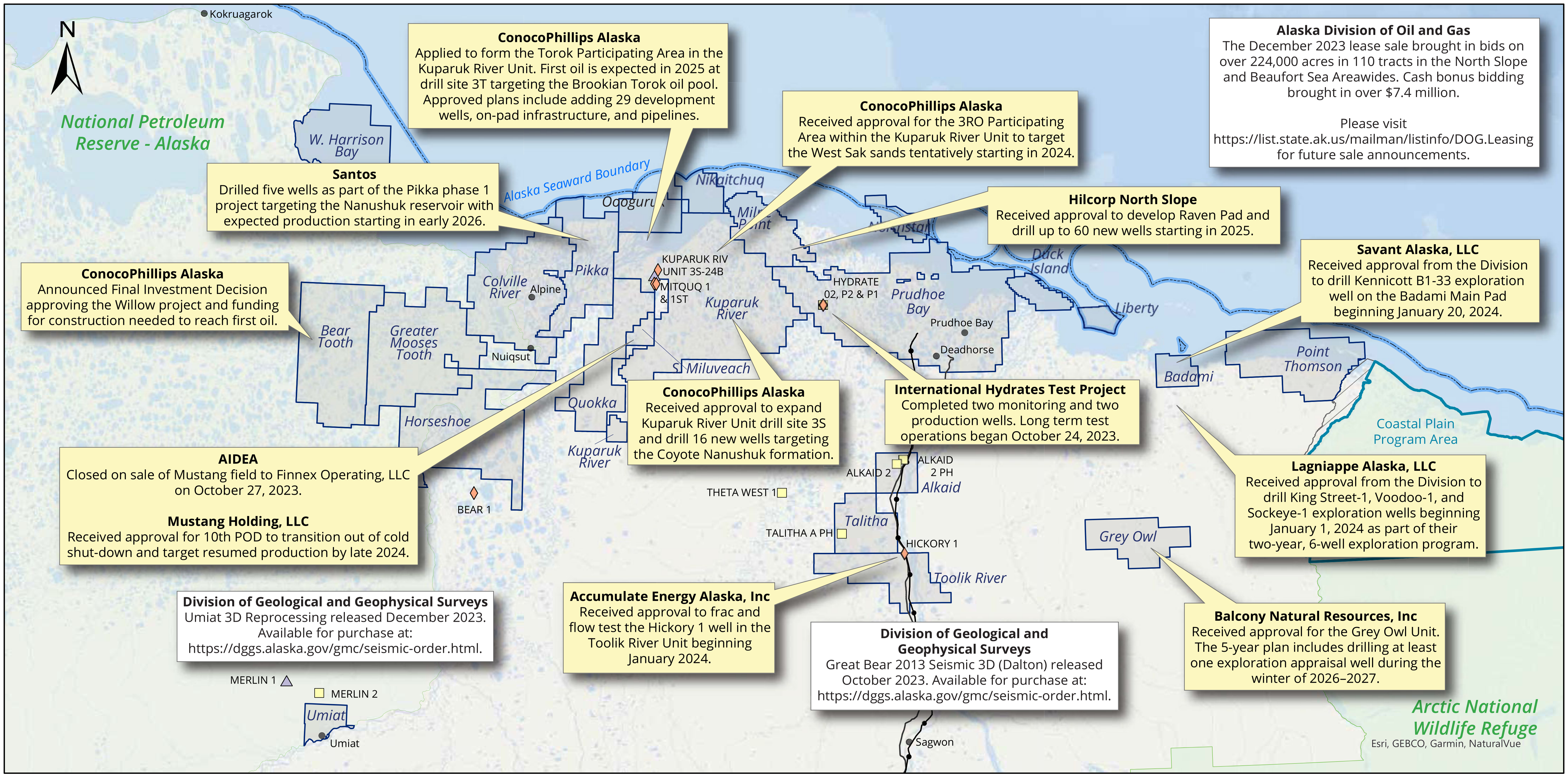
•Hilcorp Alaska LLC acquired permission to conduct 21.3-line miles of marine seismic west of Ninilchik within the Kenai Peninsula Borough. Acquisition of four lines completed October 2023.

•Cook Inlet Natural Gas Storage Alaska LLC prepared to expand CINGSA by drilling two new wells.

•Hilcorp Alaska LLC gained approval in part for the formation of the Pearl Participating Area and the expansion of the Ninilchik Unit.

•Hilcorp Alaska LLC was approved for a 10-year term easement to study the feasibility of producing natural gas from the Baker platform. Additionally, nearby infrastructure will be utilized for alternative energy projects such as tidal energy, wind energy, and carbon capture, utilization, and storage in the former Middle Ground Shoal Unit. ●

Contact Kay Cashman at publisher@petroleumnews.com



Oil and Gas Exploratory Wells (Bottom hole)

Year Completed

- 2023
- 2022
- 2021

Trans-Alaska Pipeline System

Dalton Highway

Federal Lands

Disputed Ownership

Coastal Plain Program Area

Towns

Unit Boundary

0 5 10 15 20 Miles

North Slope Oil and Gas Activity Map

State of Alaska
Department of Natural Resources
DIVISION OF OIL AND GAS

December *2023*

Map Location

The accuracy of this map is subject to pending decisions currently on appeal and other administrative actions. Please visit www.dog.dnr.alaska.gov/Information/MapsAndGIS to see our most current maps.

● EXPLORATION & PRODUCTION

Hilcorp plans 2D survey along Sterling Hwy

Line to be between Clam Gulch and Anchor Point, some 46 miles of survey, using 2 vibe trucks over 14-24 days beginning in March

By KRISTEN NELSON
Petroleum News

Hilcorp Alaska has applied for a permit for a 2D seismic line on the Kenai Peninsula running some 46 miles from Clam Gulch to Anchor Point along the Sterling Highway. The Alaska Department of Natural Resources' Division of Oil and Gas said in a Jan. 22 public notice that comments on the project are due by 4:30 p.m. Feb. 5.

The division said the survey is to provide seismic data for evaluation of future drilling targets and to fill in current gaps in data.

In its application Hilcorp said two vibe trucks will be used and will travel along the Sterling Highway. The trucks will use a plate that lowers and makes contact with the ground and then vibrates. As the trucks move along the highway, they will stop and shake every 55 feet for about a minute before moving on and are expected to move some 3 miles each 24 hours for some 46 miles total.

"There will be no surface disturbance at any point before, during or after the duration of this project," Hilcorp said.

Nodal receivers

Nodal receivers will be placed every 27.5 feet off the highway within the highway right of way. The receivers will be placed 10-25 feet from the paved road, "depending on the area and to avoid any interference with snowplowing and/or road maintenance operations," the company said.

Some 1,240 nodal receivers will be used, placed by a utility terrain vehicle operating off the highway, with spacing between trucks and receivers varying to avoid driveways, bridges, etc. Hilcorp said no vibration will be done on bridges.

"There will be no surface disturbance at any point before, during or after the duration of this project," Hilcorp said.

The company said a traffic control plan has been developed, but noted the project will not require complete lane closures. It said the vibe trucks will use the shoulder of the road as much as possible.

Hilcorp said it would send notice letters to property owners along the Sterling Highway where it will be working and said work will not be done around bus stops during school zone hours, with needed crew changes to be scheduled for those times.

Seismic nodes will be deployed beginning Feb. 23, with the seismic survey scheduled for March 1 through April 14, followed by demobilization through May 14. ●

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CHEVRON ASSETS

Chevron's other Canadian operations are unaffected, the spokesman said.

After the Hess announcement, Chevron said it planned to focus more than 75% of its upstream capital expenditures on U.S. shale formations in the Gulf of Mexico, the Eastern Mediterranean, Guyana, Australia and Kazakhstan.

The company said it would also put high-return assets up for sale to diversify its portfolio across asset types and geographies and to achieve high cash margins and low carbon-intensity production.

Chevron's other Canadian operations are unaffected, the spokesman said.

Pending regulatory approval

The Hess deal is pending regulatory approvals and is expected to close in the second half of 2024.

Brian Lidsky, director of Energy Advisors Group, estimated the Alberta properties should be worth US$900 million based on recent acquisitions of Duvernay properties by Calgary-based Crescent Point Energy and others.

Athabasca Oil and Cenovus Energy, two major Alberta oil sands players, have formed a joint venture to accelerate their activity in the Duvernay play.

The formation has seen a surge in activity and productivity improvements, with costs coming down from as high as US$14.85 million per well a decade ago to US$10 million today, analysts at brokerage firm Eight Capital said.

"The Duvernay is starting to become a key focus for the industry and is thus likely to get investors' attention in 2024," Eight Capital analysts said in a recent research note. "Operators have done enough drilling to understand how to optimize the technology."

—GARY PARK

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OIL PRICES

The brutal freeze hit the supply side as well, striking U.S. oil production.

Production across the nation was curtailed by some 10 million barrels the week of Jan. 19, according to market participants who asked not to be named because the information is private, Bloomberg said in a Jan. 20 report. The Permian basin of Texas and New Mexico saw a drop estimated at 6 million barrels, while shut-in output in the North Dakota Bakken was some 3.5 million barrels.

Natural gas gathering systems taking produced gas from oil wells clog with liquids in extreme cold, disabling compressors and causing the wells to be shut-in to avoid flaring, according to Lynn Helms, North Dakota mineral resources director.

"It will be a long, slow recovery," Helms said on a webcast. "January will be a very, very bad month."

On the demand side, traders reacted favorably to proposed Chinese economic stimulus.

China may soon release some 2 trillion yuan ($280 billion) to rescue mainland and Hong Kong stock markets, by requiring state-owned enterprises to repatriate cash held overseas to buy shares, according to Bloomberg reports.

The U.S. dollar fell against a basket of other currencies, making oil easier to buy for holders of other currencies.

Meanwhile, the Red Sea remained a hot zone, as a coalition of 24 nations led by the U.S. and UK launched new retaliatory strikes against Houthi fighters in Yemen, Reuters reported Jan. 24. The U.S. also struck Iran-linked militia in Iraq Jan. 23, following an attack on an Iraqi air base that wounded U.S. forces.

Meanwhile, the Red Sea remained a hot zone, as a coalition of 24 nations led by the U.S. and UK launched new retaliatory strikes against Houthi fighters in Yemen, Reuters reported Jan. 24. The U.S. also struck Iran-linked militia in Iraq Jan. 23, following an attack on an Iraqi air base that wounded U.S. forces.

ANS fell 25 cents Jan. 23 to close at $80.09, as WTI dropped 82 cents to close at $74.37 and Brent slid 51 cents to close at $79.55.

On Jan. 22 ANS jumped $1.18 to close at $80.34, WTI vaulted $1.78 to close at $75.19 and Brent leapt $1.50 to close at $80.06 after Ukraine reportedly struck a major Russia fuel terminal Jan. 21, sparking fears of supply disruptions.

The Security Service of Ukraine hit the Ust-Luga Complex near St. Petersburg with drones, igniting a large-scale fire, Ukrainian officials said, according to a Wall Street Journal report.

Russian gas company Novatek, which owns the fuel terminal, said that work there had been halted and that the fire had been brought under control. It blamed the fire on "external action."

The processing facility produces oil products, including jet fuel and fuel oil, which are exported to international markets, the company said.

The attack highlights the vulnerability of these facilities to drone strikes, not just in Russia but also elsewhere, such as the Middle East, said Andrew Lipow, president of Lipow Oil Associates.

ANS trimmed 47 cents Jan. 19 to close at $79.16, while WTI slid 67 cents to close at $73.41 and Brent lost 54 cents to close at $78.56.

ANS jumped $1.21 on Jan. 18 to close at $79.63, as WTI leapt $1.52 to close at $74.08 and Brent jumped $1.22 to close at $79.10.

From Wednesday to Wednesday, ANS gained $2.37 over its Jan. 17 close of $78.42 for a Jan. 24 close of $80.79.

On Jan. 24, ANS commanded a $5.70 premium over WTI and a 75-cent premium over Brent.

Saudis take one for the team

Saudi Arabia has slashed its crude production to lows not seen since the pandemic to defend oil prices, S&P Global said in a Jan. 22 note.

Saudi Arabia has committed since July to an output of 9 million barrels per day, but recently it has underpumped that target, self-reporting production of 8.82 million bpd in November and 8.94 million bpd in December, according to data published by the Organization of the Petroleum Exporting Countries.

"The pandemic has shown Saudi Arabia can go lower (in terms of output), but probably that would require a recession and falling oil demand and would require other OPEC+ (members) to cut as well. That is not our base case," said Giovanni Staunovo, commodity strategist at Swiss investment bank UBS.

Analysts with S&P Global Commodity Insights see a new round of OPEC+ cuts in the first quarter — the fifth since October 2022 — to counteract rising non-OPEC supply.

Structuring the cut would require deft negotiations, as Saudi Arabia, which has gone from a quota of 11.03 million bpd in September 2022 to 9 million bpd, is likely to find a unilateral cut without cooperation from other members "pretty tough to swallow," said Jim Burkhard, S&P Global VP of oil markets, energy, and mobility. ●

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Petroleum news

Oil Patch Bits

Coffman welcomes Amber Benham to its team

Coffman Engineers Inc. said Jan. 19 that it is pleased to welcome Amber Benham to its electrical department and congratulates her on earning her Alaska professional engineering license in control systems engineering.

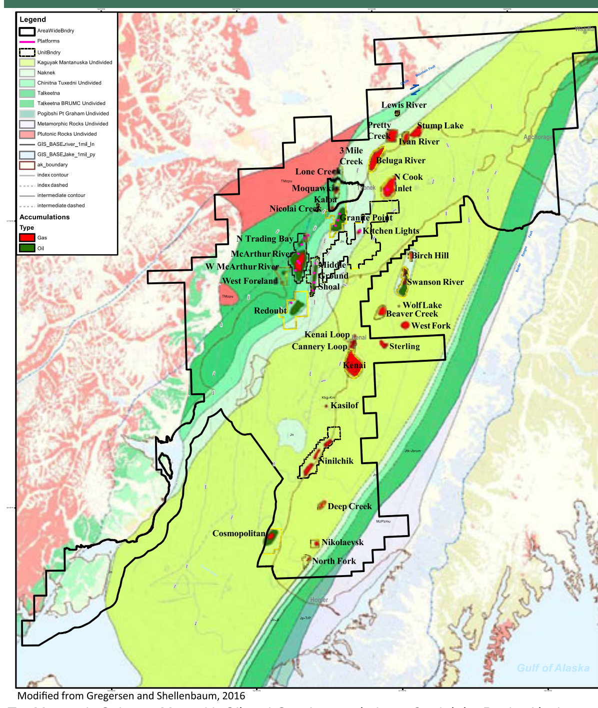
Benham received two Bachelor of Science degrees in chemical engineering and biological engineering from Montana State University. She has 9 years of experience in the refining industry as a process control and control systems engineer and brings a new capability to Coffman's line of services.

Her experience includes control system design and automation, alarm and safety systems, instrumentation, and distributed control system configuration. Prior to joining Coffman, she served as a process control engineer on the Marathon Marinez Renewable Fuels project and at Marathon Kenai Refinery. During her time at Anvil, Benham also supported two separate DCS modernization projects for Shell's Puget Sound refinery.

"We are thrilled to have Amber join the Coffman team. Her experience and skillset with process control and safety systems complements many of the services we provide and expands upon the engineering services we are able to support our valued clients with. We welcome Amber and congratulate her on becoming Coffman's first professional Control Systems Engineer and look forward to her future here at Coffman," said principal electrical engineers, Logan Haines, PE and Nicholai Smith, PE, who both lead the Anchorage office electrical department.

AMBER BENHAM

COOK INLET GEOLOGY



Modified from Gregersen and Shellenbaum, 2016
Top Mesozoic Subcrop Map with Oil and Gas Accumulations, Cook Inlet Basin, Alaska

Quick Look Guide to Cook Inlet Oil and Gas
LS Gregersen, 3-13-2020

Two Sources of Gas In Cook Inlet Basin

1. Biogenic gas from coals.
2. Oil migrated from source rocks, creating associated gas.

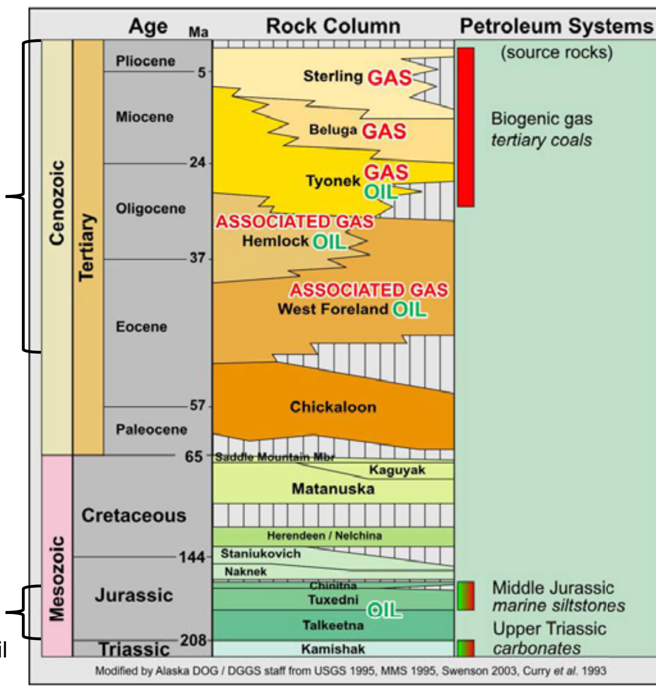
Majority of oil and gas production is from Tertiary reservoirs

Oil seeps; TBU M-28 produced oil

More resources from the Department of Geological & Geophysical Surveys (DGGS)

- **Cook Inlet geology and hydrocarbon potential (project link)**
- **Seismic and well data (catalog link)**

Cook Inlet Stratigraphic Column



Modified by Alaska DOG / DGGS staff from USGS 1995, MMS 1995, Swenson 2003, Curry et al. 1993

Cook Inlet Gas Overview 5

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INLET GAS

Gas Important, "tells us why Cook Inlet gas is a vital energy resource … we're talking about heating your home," Nottingham said, noting that "all told about 70% of Alaskans are affected by Cook Inlet gas in some form or fashion … from both a heating and an electricity standpoint."

In regard to natural gas, the utility Enstar serves more than 440,000 people and operates in over 25 communities throughout Southcentral Alaska. The Interior Gas Utility, or IGU, serves more than 2,400 people.

In regard to electricity, Nottingham said Chugach Electric serves more than 302,000 people in Anchorage, Whittier, Girdwood and Fairbanks.

Matanuska Electric, or MEA, serves the Mat-Su Borough and Chugach and Eagle River, over 180,000 people. Homer Electric serves nearly 36,000 people.

A pie chart included in the first slide shows the annual amount of Cook Inlet utility gas under contract: Enstar 36 billion cubic feet, Chugach Electric 21 bcf, MEA 6 bcf, IGU 5 bcf and Homer Electric 4 bcf.

Cook Inlet, Nottingham said, is a large mature oil and gas basin that has produced more than 1.4 billion barrels of oil and 12 trillion cubic feet of gas through 2023.

Currently, there are 26 producing fields operated by eight different companies in the basin, involving some 200 oil and gas leases in Cook inlet.

Natural gas production has been declining since 1990, when gas output peaked at more than 850,000 thousand cubic feet per day (853,476 mcf/d).

Current production is just over 200,000 thousand cubic feet per day.

Cook Inlet geology

Nottingham then talked about Cook Inlet basin geology from what he described as an engineer's (his) point of view.

There are two sources of natural gas in the Cook Inlet basin, he said:

—Biogenic gas from coals.

—Oil migrated from source rocks, creating associated gas.

The majority of oil and gas production is from Tertiary, or younger, reservoirs.

The geology is described in a slide called Cook Inlet Geology.

Another slide used by Nottingham lists all the Cook Inlet fields, although some of them are no longer in production. The fields are: Wolf Lake, West McArthur River, West Fork, West Foreland, Trading Bay, Three Mile Creek, Swanson River, Stump Lake, Sterling, Redoubt Shoal, Pretty Creek, North Fork, North Cook Inlet, Ninilchik, Nikolaevsk, Nicolai Creek, Moquawkie, Middle Ground Shoal, McArthur River, Lone Creek, Lewis River, Kustatan, Kitchen Lights, Kenai Loop, Kenai C.L.U., Kenai, Kasilof, Ivan River, Hansen, Granite Point, Deep Creek, Beluga River, Beaver Creek and Albert Kaloa.

All the well-funded big oil and gas companies left Cook Inlet in the last 15 years, leaving small companies operating in the area, including firms such as Hilcorp which specializes in rejuvenating mature fields.

COOK INLET PRODUCTION BY FIELD:

Field	Operator and lessees	2023 Gas Production	2023 Oil Production
Kenai Loop	AIX Energy LLC	0.66.bcf	
Nicolai Creek	Amaroq Resources, LLC	0.1 bcf	
Hansen	Bluecrest Alaska Operating LLC	0.43 bcf	713 bopd
Redoubt Shoal	Cook Inlet Energy, LLC.	0.04 bcf	443 bopd
West McArthur River	Cook Inlet Energy, LLC.	0.05 bcf	586 bopd
Kitchen Lights	Furie Operating Alaska, LLC; Cornucopia Oil & Gas Company; A. L. Berry; Danny Davis; Taylor Minerals, LLC; Corsair Oil & Gas	3.58 bcf	
Beaver Creek	Hilcorp Alaska, LLC	2.73 bcf	382 bopd
Beluga River	Hilcorp Alaska, LLC; Chugach Electric Association	**12.13 bcf**	
Deep Creek	Hilcorp Alaska, LLC	1.27 bcf	
Granite Pt	Hilcorp Alaska, LLC	1.09 bcf	2,232 bopd
Ivan River	Hilcorp Alaska, LLC	2.14 bcf	
Kenai	Hilcorp Alaska, LLC	6.78 bcf	
Kenai C.L.U.	Hilcorp Alaska, LLC	1.97 bcf	
Lewis River	Hilcorp Alaska, LLC	0.22 bcf	
McArthur River	Hilcorp Alaska, LLC	4.85 bcf	2,589 bopd
Middle Ground Shoal	Hilcorp Alaska, LLC	0.00 bcf	0 bopd
Red 1 Well	Hilcorp Alaska, LLC	0.07 bcf	
Ninilchik	Hilcorp Alaska, LLC	**14.31 bcf**	
North Cook Inlet	Hilcorp Alaska, LLC	**12.34 bcf**	
Seaview	Hilcorp Alaska, LLC	0.00 bcf	
Swanson River	Hilcorp Alaska, LLC	2.59 bcf	732 bopd
Trading Bay	Hilcorp Alaska, LLC	0.4 bcf	890 bopd
North Fork	Vision Operating, LLC	0.79 bcf	

Source: AOGCC through November 2023

bcf = billion cubic feet

bopd = barrels of oil per day

https://dog.dnr.alaska.gov/Information/MapsAndGis

2024-01-17 Cook Inlet Gas Overview

Cook Inlet, Nottingham said, is a large mature oil and gas basin that has produced more than 1.4 billion barrels of oil and 12 trillion cubic feet of gas through 2023.

Gas storage

Nottingham also talked about gas storage in the basin.

Gas storage is a production and injection operation used to mitigate fluctuating demand for natural gas that is driven by swings in ambient temperature.

During times of peak demand, more gas is called for (by consumers) than is deliverable from producing reservoirs. By placing gas in storage during times of low demand, a greater volume of gas is available for withdrawal during times of peak demand.

The Cook Inlet basin has four storage facilities. They are as follows:

Established in 2001 the Swanson River (federal) unit has a capacity 3.4 bcf and is currently operated by Hilcorp.

Established in in 2005, Pretty Creek gas storage has a capacity of 3 bcf and is also currently operated by Hilcorp.

Kenai Gas Pool 6, established in 2006, has a capacity of 50 bcf, and is operated by Hilcorp.

The fourth is Cook Inlet Natural Gas Storage Alaska, or CINGSA, which was established in 2011. It has gas storage capacity of 18 bcf, and is regulated by the Resource Commission of Alaska. ●

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NORTHSTAR INJECTION

20th POD

In the 20th POD, effective Feb. 13, 2024, through Feb. 12, 2025, Hilcorp will implement water injection in NS-19 to maintain pressure in the Kuparuk reservoir, requiring modification of surface equipment so produced water can be routed to that well. There will also be facility work to expand the gas lift system so that additional wells can be placed on gas lift, the division said. Hilcorp will continue evaluation of coiled tubing drilling options at Northstar and continue maintenance of the island's coastal defenses.

The Northstar unit was formed in 1990 and has 20,134.7 acres, four state and three federal leases, with joint management by the division and the U.S. Department of the Interior's Bureau of Safety and Environmental Enforcement.

In November, the latest month for which Alaska Oil and Gas Conservation Commission production data are available, Northstar production averaged 5,722 barrels per day, down 18.6% from November 2022, 54.2% crude (3,100 bpd) and 45.8% natural gas liquids (45.8%). Northstar has the highest percentage of NGL production on the North Slope.

—KRISTEN NELSON

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ACEP STUDY

six main components: scenario development; electricity load forecasting; power generation analysis; power transmission analysis; and economic analysis. Telos Energy Inc., a company that specializes in the analysis of isolated electrical systems, participated in the study. And the project team consulted with a technical advisory group from the four Railbelt electricity cooperatives, the Alaska Energy Authority and the Railbelt Regional Coordination Group.

Cicilio said that the study evaluated four scenarios: a continuation of the current arrangements for power generation; the use of a combination of wind, solar and hydro; the use of wind, solar and tidal power; and the use of wind, solar and nuclear power. All the scenarios assumed a roughly doubling of electricity demand by 2050 as a consequence of population growth and the increased use of electric vehicles and electrically powered heat pumps for heating buildings.

Potential decarbonization projects

To identify plausible decarbonization projects for the scenarios the team primarily used existing projects or projects that are being proposed and studied. However, for wind and solar generation, the analysts did add some other potential projects. According to the project report, wind sites, for example, would have proximity to the transmission system, at locations with viable wind resources. The East Forelands site on Cook Inlet was selected for a potential tidal energy system, and nuclear generation sites were assumed at Healy in the Interior and at Beluga in Southcentral Alaska, the report says. And for future hydro power generation the project team assumed the development of the major Susitna-Watana hydropower project on the Susitna River that was proposed a number of years ago.

The team found that some level of gas-fueled power generation would be needed to ensure adequate power supply stability and reliability in all of the scenarios other than the scenario involving nuclear power. However, gas consumption in the decarbonizing scenarios would be very much lower than in the "business as usual" scenario. In the case of the nuclear power scenario the team discounted the continued use of natural gas fueled power generation, given an assumption that nuclear power, in the form of small modular reactors, would prove more expensive than gas fueled power but would be able to underpin electricity supply stability in a similar manner to gas generation.

Assistant professor Jeremy VanderMeer told the committee that the team developed what seemed a reasonable portfolio of generation assets for each scenario. He commented that wind and solar power proved the cheapest forms of power generation all scenarios, but that there is an upper limit to the amount of these types of generation that can be used in practice, given the cost of curtailing peaks in wind and solar output if there is too much of these resources in the system. Moreover, sources of firm power involving some combination of hydro, nuclear, fossil fuel and batteries would be necessary to ensure supply reliability.

According to the study report, zero-carbon power generation in the low-carbon scenarios would range from 70% of total generation in the wind/solar/tidal scenario to 96% in the wind/solar/nuclear scenario. There would be 11.4% zero-carbon generation in the "business as usual" scenario.

Detailed simulations

Derek Stenelik from Telos Energy said that the project team conducted detailed simulations of how each scenario might operate on an hour-by-hour basis across an entire year. The simulations took into account changing electrical loads; the availability of wind and solar; reliability needs; and operating constraints. The simulations assumed that a single entity controls the optimization of power dispatch across the system.

Using a cost simulation computer system that is widely used in the industry and is used by the Railbelt utilities, the researchers analyzed the potential operation of the system, the system stability, fuel consumption and operating costs.

The team found that in the three decarbonization portfolios wind and solar, currently the lowest cost renewable energy resources, formed the backbone to power generation, supplying more than 50% of the energy. And ensuring reliable electricity delivery on a typical winter day, for example, involved much more moving around between different generation sources than happens in the current electrical system.

Battery technology is a key enabler, both to ensure grid stability and to shift energy from times of high renewable energy production to times of low production. However, further analysis of the impact of very high renewal power output on the system is needed, Stenelik said.

Needs an adequate transmission system

And an adequate transmission system is critical to all of the scenarios, with the decarbonization scenarios requiring much more electrical flow in both directions, north and south, across the Railbelt transmission network than in the "business as usual" situation. The transmission grid needs to be larger than at present, able to transfer more power, to be more operationally flexible and to be coordinated by a single entity, Stenelik said.

Natt Richwine from Telos Energy said that decarbonization would involve a major shift in the manner in which the transmission system operates, given that power generation would shift significantly from the use of big rotating generators such as gas turbine systems to the use of computer driven inverter technologies that connect solar, wind farms and battery systems, for example, to the grid.

System stability

The project team conducted simulations of how the electrical system would work using today's conventional technologies and identified significant issues with system stability. After simulating different means of addressing this problem the team determined that some means of mitigating stability problems would be required. The team assessed the potential use of a new technology called grid forming inverter technology to address this issue and as a consequence recommends the use of this technology in conjunction with decarbonizing the grid. Essentially, computer technology at each generation or battery storage site would interconnect with each other, to help coordinate all of the plants on the high voltage electrical system.

High capital costs

Research professor Steve Colt said that the capital costs of implementing any of the decarbonization scenarios would be much higher than the capital costs of maintaining "business as usual." The wind, solar and hydro scenario would be especially expensive at around $12 billion, in particular because of the high cost of building the Susitna-Watana hydro system. The estimated capital costs of the other two decarbonization scenarios range from a little under $8 billion to around $10 billion. The capital cost estimates assume that projects would be conducted in time to qualify for federal investment tax credits which expire in 10 years. The study report indicates that the capital cost estimates include the potential costs of necessary transmission grid upgrades.

Also, in any decarbonization scenario there is a significant but not overwhelming cost associated with the batteries and other technologies that would be needed to support system reliability, Colt commented.

Business as usual also expensive

On the other hand, continuing with business as usual would involve billions of dollars of expenditure over the years for the purchase of natural gas fuel. That would push up the total cost to something similar to the cost of a decarbonization option. The purchase of gas would involve continuous fuel costs, while the capital costs would presumably be recovered through electricity rates over the years. Thus, although there are huge uncertainties over what the actual cost of any scenario might be, it appears that all of the scenarios, including "business as usual," fall within a broadly similar cost ballpark, Colt suggested.

Asked how legislators might influence decisions over future developments in the electrical system, Stenelik commented that it would be helpful to put some certainty into the energy transition through some form of energy standard or renewable portfolio standard. ●

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COTTONFIELD WELL

adjacent landowners and maximize resource recovery by establishing default limits on how close, under the land's surface, oil and gas wells can be to property lines where ownership changes hands," the commission said.

The commission's Nov. 16, 2023, notice set a tentative hearing date, and a Dec. 8 date for requesting the hearing. Local residents had queried the commission about the proposed work prior to the public notice, and the commission provided information on its role and on the possibility of a public hearing, which was requested.

At that Jan. 18 hearing there was public testimony and the commission received written comments including from landowners in the vicinity of the Cottonfield prospect.

Concerns expressed in the written comments and in the hearing ranged from offers Hilcorp was making to adjacent landowners to concerns about the safety of adjacent properties in the event of a well blowout and emergency planning issues.

Bluff erosion was cited along with possible environmental side effects such as the impact on wetlands, drinking water resources and lack of evacuation plans in the event of an emergency caused by the drilling.

Hilcorp provided responses to some of the questions raised by commissioners and the public following the hearing in an email to the commission.

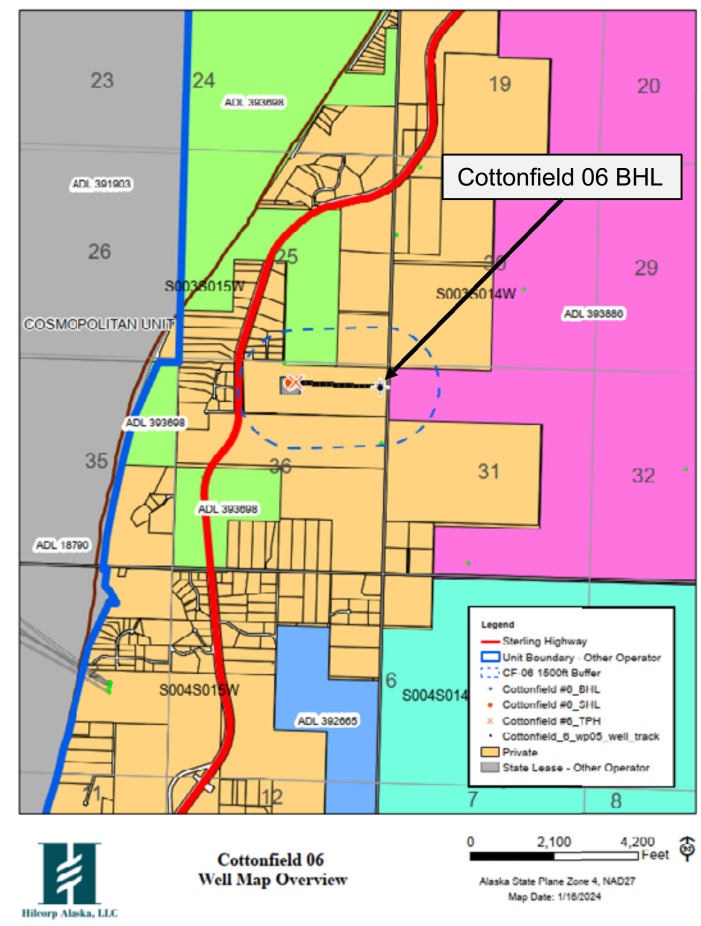
The location of the pad for the Cottonfield 6 was questioned in public comments at the hearing, and Hilcorp said the pad was originally planned for the eastern edge of its property, but was moved to the west because of topography, including a steep slope on the eastern portion of the property and concerns about impact on wetlands.

Possible hydrogen sulfide exposure was another issue raised in the public comments at the hearing, and Hilcorp told the commission in its email that data from wells in the region indicate hydrogen sulfide is not present in the area of the Kenai Peninsula where this well will be drilled.

Cottonfield 06 Well Overview

CF-06 Exploration Well

- First exploration well drilled by Hilcorp within the Cottonfield Prospect
- Targeting the Undefined Cottonfield Gas Pool (Sterling, Beluga, and Tyonek Formations).
- Total Depth ("TD") of 7,383' MD. Top of the Productive Horizon will be from 1,500'MD to TD.
- Due to special geologic conditions, the targeted sands in CF-06 will not conform to statewide spacing requirements.
- Well location determined using various sources of confidential subsurface data to target and verify the presence of a deep structure.
- Following completion of well and assuming success, testing and flaring will be conducted intermittently for no longer than 45 days.



The commission asked about Hilcorp's wellbore design and cementing, and the company said it will pump excess cement and if cement does not come to the surface, the company will cease operations and notify the commission and then develop a remedial cementing plan.

Hilcorp said it is not aware of any groundwater contamination from drilling operations on the Kenai Peninsula and said its "cementing and surface casing procedures are industry standard."

In response to concerns from the public about lack of involvement of local emergency responders in plans for the well, Hilcorp said two members of its safety team sit on the Kenai Peninsula Borough Local Emergency Planning Committee and regularly attend its meetings, and added that Harvest, its pipeline subsidiary, attends the final meeting of the year and advises responders on the status of pipelines.

In discussing its request for a spacing exception for Cottonfield 6 at the commission hearing, Hilcorp said it was targeting the undefined Cottonfield gas pool in the Sterling, Beluga and Tyonek formations, and said the discontinuous nature of the sands made a spacing exception necessary. The measured depth of the well will be 7,383 feet, with the productive horizon from 1,500 feet measured depth to total depth. The location was determined with confidential subsurface data.

Asked about the depth of water wells in the area, Hilcorp said public data shows the deepest wells within 5 miles to be 200 feet, with data for the nearest wells suggesting the deepest freshwater occurs at about 150 feet.

The company said that following successful completion of the well, there will be intermittent testing and flaring for no more than 45 days.

Hilcorp told the commission in its Nov. 7 application for a spacing exception that it expected drilling operations to begin Jan. 18, although as of Jan. 24 the commission had yet to issue a decision on the spacing exception, which will occur prior to issuance of a drilling permit.

Also in its application Hilcorp told the commission that upon successful completion of the Cottonfield 6 well, and prior to bringing the well online, it would apply to the Department of Natural Resources' Division of Oil and Gas for formation of the Cottonfield unit and initial participating area.

—KRISTEN NELSON

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