Petroleum news

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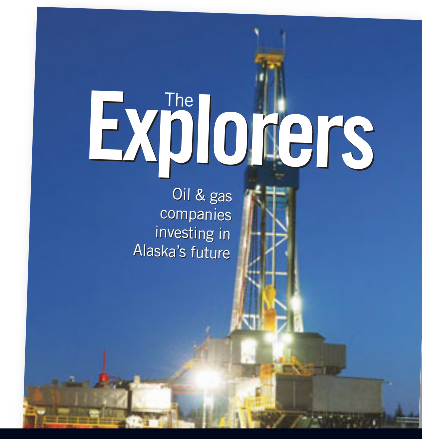

page 8 Jade cuts deal with Point Thomson owners to drill Sourdough in 2020

Oil Search confirms plans for North Slope at annual meeting

Oil Search's annual meeting on May 10 didn't yield any surprises for Alaska. As expected, the Australian oil and gas company remains enthusiastic about its development and exploration plans for the North Slope.

Its concept for its first oil production facility in the Pikka unit west of the central North Slope still shows 120,000 barrels per day of light oil from 15 producing wells, paired with 15 injectors, that utilize two drillsites, with a third site "in reserve."

The oil is initially expected to come from the Nanushuk formation, but Oil Search is also looking at tapping the deeper Alpine reservoir. Partner Armstrong Energy's founder Bill Armstrong said from the start that there were at least six intervals in Pikka wells that would eventually be tapped, the largest of

see **OIL SEARCH PLANS** page 15

SALSA on fall lease sale menu again this year; no takers in 2018

Last year the state offered Special Alaska Lease Sale Areas, SALSA, in its North Slope and Beaufort Sea areawide lease sales. SALSA is on the menu again this year.

The Alaska Department of Natural Resources' Division of Oil and Gas has posted an updated version of the SALSA data guide online at http://dog.dnr.alaska.gov/Library/SALSA.

"We received enthusiastic feedback about the 2018 SALSA program and the data compilation associated with the program," DNR Commissioner Corri Feige said in a May 15 statement. "By signaling our intentions earlier this year, potential bidders will have much more time to evaluate and consider opportunities."

The bid opening for the fall 2019 sale is tentatively set for 9

see **SALSA OFFERING** page 16

RCA sets Chugach Electric, ML&P agenda; hearings to end in August

The Regulatory Commission of Alaska has issued an order setting a hearing schedule for its review of Chugach Electric Association's proposed purchase of Municipal Light & Power. The schedule involves two hearings, the last of which will end on Aug. 27. The statutory deadline for the commission to make a ruling in the case is Nov. 19.

In its order, issued on May 8, the commission is allowing Alaska Railbelt utilities Homer Electric Association, Golden Valley Electric Association and Matanuska Electric Association to intervene in the proceedings. HEA and GVEA have expressed concern about the potential impact on their businesses of the

see **RCA AGENDA** page 13

More stalling on Trans Mountain; may be pivotal in October election

The Canadian government of Prime Minister Justin Trudeau shows every sign of turning the Trans Mountain pipeline project into a pivotal issue in the federal election expected sometime in October, ignoring the fact that it has invested C$4.5 billion in the existing and proposed expansion of the shipping system from Alberta to the Pacific Coast.

What has long been suspected became a fact in late April when Natural Resources Minister Amarjeet Sohi said that, even though the Trudeau cabinet will be able to make a final decision on TMX by its latest deadline of June 18, he could not guarantee a verdict before the fall campaign.

"I cannot commit to (meeting the June 18 target) because it's not my decision," he told reporters. "It's the decision of the cabinet."

see **TRANS MOUNTAIN** page 11

EXPLORATION & PRODUCTION

Placer POD extended

After DNR ruling DOG moves the end date for AEX's current plan to July 10

By ALAN BAILEY
Petroleum News

On May 10 Alaska's Division of Oil and Gas extended the end date for ASRC Exploration LLC's 2018 plan of development for the Pacer unit from March 31 to July 10 of this year. The agency was responding to an April 18 decision by the Alaska Department of Natural Resources over an appeal by AEX against the March 31 deadline for the plan. AEX must now file a proposed 2019 plan by June 10. The division ruling comes as part of a complex series of interactions between AEX and state regulators regarding the timing and content of AEX's plans for the unit.

AEX, the operator and sole working interest owner for the Placer unit, wants to develop a known oil resource in the unit. To maintain the unit, the company must conduct activities under an approved plan of development, designed to bring the unit into production. A plan of development typically runs for a year, with a further continuing plan needing to be approved before the current plan expires.

Well re-entry required

In the case of the Placer unit, after AEX filed its 2018 plan, scheduled to begin in September of last year, the division only approved the plan to run for nine months, with a termination date at the end of May 2019. The rationale was that the plan included a requirement to re-enter and conduct testing in

see **PLACER POD** page 16

FINANCE & ECONOMY

Kitchen unit auction?

After a successful year, Cook Inlet gas field foreclosure sale looms May 31

By KAY CASHMAN
Petroleum News


SCOTT PINSONNAULT

Furie Operating Alaska had been making good progress in the Kitchen Lights offshore gas field, having completed its planned 2018 drilling program and thus curing a 2017 default with the Alaska Department of Natural Resources' Division of Oil and Gas, along with securing approval in December of its new plan of development for the Cook Inlet unit.

Then in early January, operator Furie ran into problems with hydrate plugs at the Kitchen Lights' onshore processing facility and in the 15-mile subsea pipeline from the offshore production platform, which eventually slowed natural gas delivery to a trickle later that month and put Furie's contract with utility Enstar Natural Gas in jeopardy. Gas output fell from 739,023 thousand cubic feet to a mere 1,886 mcf in February.

The next blow came in mid-April when a public notice of a foreclosure sale auction was posted in the Anchorage Daily News, followed by the same in Hart Energy's Industry Voice.

The party behind the foreclosure was lender Energy Capital Partners, or EPC, which scheduled a May 10 auction for collateral held by borrowers,

see **KITCHEN AUCTION** page 14

FINANCE & ECONOMY

Alberta sounds alarm

Collapse of 282 producers in 5 years, 53,200 direct job losses, tax boondoggle

By GARY PARK
For Petroleum News

The number of companies exploring for and producing oil and natural gas in Western Canada slumped from 1,616 four years ago to 1,334 at the end of 2018, down 17.5%.

Direct employment in the sector is forecast to drop 23% to 173,300 from 226,500 in 2014.

The upshot is that municipal governments are having to raise tax rates to make up for an expected C$81 million in unpaid bills by the energy sector last year, while the Alberta government watched spending climb to C$57 billion in the last fiscal year, outpacing revenues by C$7.4 billion.

The situation is so dire that Premier Jason Kenney named a blue-ribbon panel to examine ways to end the province's record of nine deficits and only one small surplus in the last decade and report back on Aug. 15.

The panel will also devise a long-term plan to retire debt, which now stands above C$55 billion, without considering tax hikes to stabilize revenues.

For now, all the government has been able to do is blame the trends on the slump in global commodity prices, Canada's inability to build new pipelines that provide access to markets beyond North America, a lack of certainty in the regulatory regime and the gloomy outlook on stock markets, which has driven billions of investment dollars to more receptive environments.

see **ALBERTA ALARM** page 11

● GOVERNMENT

French has appealed both AOGCC decisions

By KRISTEN NELSON

Petroleum News

Hollis French, formerly chair of the Alaska Oil and Gas Conservation Commission, appealed a decision of the commission denying his request for a hearing on gas which leaked from a Prudhoe Bay well in 2017.

French had also requested a hearing on gas which leaked in Cook Inlet in 2017, which the commission also denied.

His first appeal to Alaska Superior Court, on the Prudhoe Bay gas leak issue, was made April 22.

That appeal was for: "Failing to calendar a hearing on waste from a North Slope well."

(See stories in April 14 and May 5 issues of Petroleum News.)

On May 1, French appealed the second AOGCC decision.

In the Cook Inlet gas leak matter, French listed three points of appeal.

He said the commission erred in three rulings it made: that it "had no jurisdiction over gas sold by a vendor"; that it "had no jurisdiction over gas metered and severed from a property"; and "that AOGCC had no jurisdiction over gas Hilcorp purchased from Harvest Pipeline."

HOLLIS FRENCH

Disagreements over scope

French had disagreements with the other commissioners on the scope of the commission's authority when he was chair.

After a December hearing requested by Kate Troll asking that the commission "prevent all non-emergency venting and flaring from Alaska oil and gas wells," the commission issued two documents, one signed by the other two commissioners and one signed by French (see story in Jan. 27 issue).

The order signed by then-Commissioner Cathy Foerster, who has since retired, and Commissioner Dan

see **FRENCH APPEAL** *page 5*

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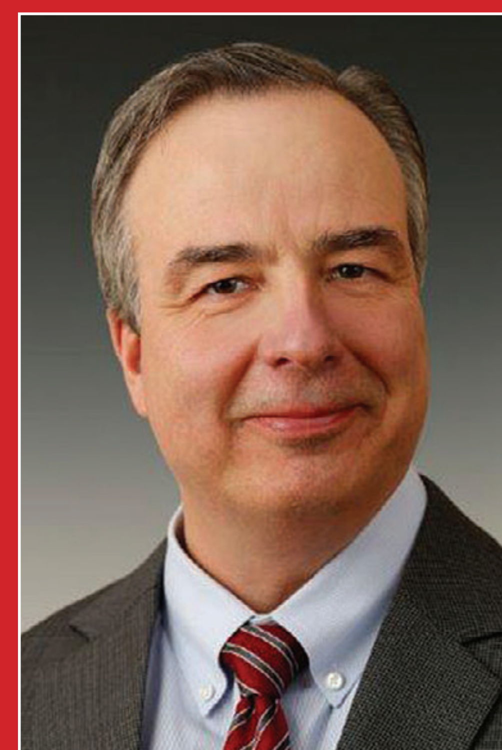
Congratulations

Congratulations ConocoPhillips!

Hats off to ConocoPhillips Alaska's Joe Marushack and his team on the culmination of a successful 8-well winter exploration and appraisal season, as well as an uptick in North Slope oil production. Output jumped from an average of 171,000 barrels a day in 2018 to 201,000 bpd in the first quarter of this year. Both accomplishments are very good news for Alaska's economy and job market.

ConocoPhillips



Joe Marushack, President
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● UTILITIES

RCA orders review of CINGSA tariff

Says non-revenue components of gas storage facility's tariff need updating in light of operational experience; questions Enstar link

By ALAN BAILEY
Petroleum News

The Regulatory Commission of Alaska has issued an order initiating a review of the non-revenue components of Cook Inlet Natural Gas Storage Alaska's tariff. In response, CINGSA has filed a request that the review should be delayed, given what it says is the significant overlap between this review and a docket currently in progress, seeking approval of CINGSA's new tariff for its services. CINGSA provides gas storage services for Southcentral Alaska gas and power utilities, enabling the utilities to warehouse gas during periods of low gas demand for use when gas demand is higher. CINGSA is the only commercial operation in Southcentral Alaska providing this type of service.

The fees and conditions associated with use of the CINGSA facility impact the cost of gas and electricity that the utilities supply to their customers.

Needs updating

The RCA says that the non-revenue terms in the CINGSA tariff were established prior to the facility going into operation in 2012. Although the terms were appropriate at that time, given various unknowns regarding the operational characteristics of the facility, the RCA thinks that the tariff needs updating, based on what is now understood.

One area of CINGSA's tariff that now needs review is the characterization of the CINGSA facility, in particular the specification of the facility's storage capacity and its performance capabilities for the injection and retrieval of gas, the RCA said.

The RCA also expressed concern about the relationship between CINGSA and Enstar Natural Gas Co. The two companies are affiliates, with Enstar operating the storage facility on behalf of CINGSA while also being a major customer. The lack of structural and informational firewalls between CINGSA and Enstar creates the potential for unreasonable tariff terms and would be illegal for natural gas infrastructure that comes under the jurisdiction of the Federal Energy Regulatory Commission, the RCA said.

Facility characterization

One area of CINGSA's tariff that now needs review is the characterization of the CINGSA facility, in particular the specification of the facility's storage capacity and its performance capabilities for the injection and retrieval of gas, the RCA said. The facility stores gas in a depleted subsurface sand reservoir of the Cannery Loop gas field on the Kenai Peninsula. At the time the facility went into operation there were significant unknowns regarding the geologic characteristics of the reservoir sands and their storage capabilities. But now those characteristics are well understood, the RCA said.

In particular, the facility has a design storage capacity of 11 billion cubic feet of gas. But there is now known to be at least an additional 4.5 bcf of available working storage capacity. That increase has resulted from the reservoir turning out to be larger than originally thought, and from approval from the Alaska Oil and Gas Conservation Commission to use higher storage pressures than had originally been planned, the RCA said.

Moreover, CINGSA has not provided a substantiated assessment of the daily injection and withdrawal capabilities of the facility, based on operational use: CINGSA needs to provide assessments of the range of reservoir pressures within which the facility can be allowed to operate, and the range of maximum injection and withdrawal rates across that pressure range. CINGSA also needs to document the impact on injection and withdrawal rates of one of the CINGSA wells being unavailable for service, the RCA said.

If the CINGSA tariff were to more accurately characterize the facility's actual storage capabilities, excess capacity above the facility's base design could be more readily and transparently acquired. That, in turn, would

see **CINGSA TARIFF** *page 7*

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PIPELINES & DOWNSTREAM

FERC to prepare EA on Nikiski LNG project

The Federal Energy Regulatory Commission said May 13 that it will prepare an environmental assessment for the proposed Kenai LNG Cool Down Project (see story in May 2 issue).

The LNG plant, built by Phillips and Marathon in the 1960s, is now operated by Trans-Foreland Pipeline Co., which owns 100% interest in Kenai LNG LLC, the company which owns the Nikiski LNG facility and export terminal. Trans-Foreland is a wholly owned subsidiary of Tesoro Alaska Co., now called Andeavor, which also operates the nearby Nikiski oil refinery. ConocoPhillips, then 100% owner of the Nikiski LNG facility, sold it to Andeavor in 2018.

The LNG plant, built by Phillips and Marathon in the 1960s, is now operated by Trans-Foreland Pipeline Co.

FERC said Trans-Foreland is proposing the addition of a 1,000 horsepower electric-driven boil-off-gas, BOG, booster compressor unit, trim vaporizers, ancillary facilities, additional LNG transfer system valves and equipment to manage existing BOG facilities "to facilitate the import of LNG to cool down the existing LNG storage tanks and associated LNG facilities," allowing the LNG facility to provide up to 7 million standard cubic feet per day of natural gas to the Kenai Refinery.

Public comments to FERC close June 12.

ExxonMobil Alaska LNG LLC and BP Alaska LNG LLC have both moved to intervene in the FERC docket, separately citing ownership of property adjacent to the Kenai LNG facility, property the companies acquired as the site for the proposed LNG plant to process North Slope natural gas.

—KRISTEN NELSON

● FINANCE & ECONOMY

IEA: Energy investment stabilizes in 2018

World Energy Investment report says higher upstream spending based on higher oil price, shift to shorter-cycle projects and shale

By KRISTEN NELSON
Petroleum News

Global energy investment was relatively stable last year at more than $1.8 trillion, following three years of decline, the International Energy Agency said in its 2018 World Energy Investment report, released earlier in May.

The report covers energy broadly providing interesting insights into changes in oil and gas investment.

Higher oil prices underpinned a 4% rise in upstream oil and gas spending, the report says, along with a move to shorter-cycle projects and shale, with 2019 spending plans pointing to a "potential new wave of conventional projects."

The shift to projects with shorter construction times limits capital risk. The upstream oil and gas industry is bringing capacity to market on average more than 20% faster than at the start of the decade, reflecting better project management, improved economics for shorter cycle technologies and industry competition, the report says.

Upstream oil and gas costs declined 30% over 2014-16, with a slight rebound in the last two years which was lower than the increase in oil prices.

"With more spending on shale and faster time to market for conventional projects, the industry is now better able to reach to changing market conditions," the report says.

More investment needed

"Continued robust demand growth for oil and gas would require a sharp pick-up in approvals of new conventional upstream projects," the report says.

To meet a trajectory consistent with the Paris Agreement oil spending, which has been lower since 2014, would need to taper further. On the other hand, if there continues to be strong oil demand, investment levels in oil "fall well short of what would be needed."

The reduction in exploration activities also resulted in "a massive reduction in discovered resources," the report says, with an average of 5.2 billion barrels of oil equivalent of conventional discoveries annually between 2014 and 2018, two-thirds lower than the average over the previous decade, with a similar trend in natural gas discoveries.

For natural gas, supply falls short of levels either under the Sustainable Development Scenario (i.e. consistent with Paris Agreement) or the New Policies Scenario (continued strong oil demand).

Modest rise in 2019

Investment in global upstream oil and gas is set for another modest rise this year, the report says.

Spending in the aggregate was slightly above guidance companies provided to the market in 2018, and IEA said it has revised its 2018 estimates for the rise in global upstream oil and gas spending from 5% to 6%, with a global estimate of $505 billion for 2019, up 6% in nominal terms, 4% in real terms, from last year.

This figure is still nearly $300 billion lower than the peak reached in 2014.

But upstream costs have dropped since 2014, the report says, and after adjusting for costs, the 35% reduction in nominal spending from 2014 to 2018 becomes "a much smaller 12% fall in activity."

The report says the main upstream story in recent years has been the shift to spending on shale, tight oil and shale gas, in the United States.

IEA said in its view the fastest growth in upstream investment this year will be conventional projects, rather than shale, which has leveled off at about a quarter of total upstream spending.

Reaction to lower prices

The report says large conventional operators have reacted to lower prices since 2014 in four ways:

*Maximizing revenue from existing operations, with the share of brownfield spending rising to 67% of the total in 2018 from less than 60% in 2016;

*Cutting costs whenever possible;

*Putting more focus on smaller assets — notably shale — that can be brought to market more quickly; and

*Deferring spending on more complex new projects "until they are redesigned and simplified to be competitive at lower prices."

The two-thirds share of total spending in 2018 going to conventional projects with a historic low, the report says, with offshore projects squeezed hard, and that portion of spending falling by more than 10% between 2016 and 2018.

Shale reached 26% of upstream

see IEA REPORT page 10

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FRENCH APPEAL

Seamount, said the witnesses at the hearing were open about the reason for the hearing — concern about climate change, and said while the commission "regulates to prevent waste, it has no authority to act regarding that subject matter," said testimony and questions at the hearing "appeared to stem from a general lack of familiarity with how the AOGCC addresses issues related to venting and flaring," and noted that the appropriate way to obtain information would be to schedule a meeting with the commission's technical staff.

French, in a separate document, said a review of available information on flaring shows "the Alaska oil and gas industry is, with the watchful eyes of AOGCC upon it, performing well or better than any other jurisdiction in the United States when it comes to conserving the state's valuable resources," but said there was room for improvement in how AOGCC handles venting and flaring information.

He also said, "it is perfectly appropriate for citizens to ask questions of their public servants, and it is not unreasonable for them to expect answers." ●

Contact Kristen Nelson
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GOVERNMENT

BSEE uses risk-based inspection program

The federal Bureau of Safety and Environmental Enforcement has reported on the results of a new risk-based inspection program that the agency has been operating over the past year. The program supplements the normal schedule of field inspections of offshore oil and gas production facilities by carrying out additional inspections of operations that appear to present especially high risk. The concept is to be more proactive in identifying risky situations before some incident occurs, BSEE says.

The reviews, together with an analysis of key performance factors, enable the identification of risk factors that deserve particular attention and that may warrant risk-based inspections.

"Implementing a risk-based inspection protocol is a move toward safer and smarter management of oil and gas operations on the outer continental shelf," said BSEE risk-based inspections program lead Jason Mathews. "The program allows BSEE to direct additional inspection resources to relatively higher risk/higher consequence facilities, to better protect workers and the environment."

BSEE started piloting the new inspection program in 2015. However, after a hiatus in the program startup and some subsequent criticism from the Government Accountability Office, in June 2017 BSEE Director Scott Angelle directed the agency to move ahead with the implementation. Following a couple of pilot runs of the program and the completion of a data review, the program went into operation in May 2018.

Seeking trends

Under the program, BSEE staff review compliance and incident data monthly, seeking trends in this data. The reviews, together with an analysis of key performance factors, enable the identification of risk factors that deserve particular attention and that may warrant risk-based inspections.

In 2018, 82 risk-based inspections were conducted; 30 to 40 further inspections are now being planned, BSEE says. As a consequence of carrying out the inspections, BSEE issued two safety alerts with 19 recommendations, requiring operators to enact corrective action plans. One particular area of concern identified in 2018 was the condition of some high-pressure vessels on offshore platforms. A previous concern had been risks associated with cranes and lifting equipment.

"We are looking beyond regulation to improve the way that safe and responsible offshore exploration, development and production are conducted on the outer continental shelf," Angelle said. "BSEE is incorporating technology, directed data collection and data analysis into our programs, and our decision-making process, as part of the continuing effort to make operations safer and smarter."

—ALAN BAILEY

● ALTERNATIVE ENERGY

Final EIS for Grant Lake hydro published

FERC has documented an evaluation of environmental impacts & development alternatives for proposed Peninsula hydropower system

By ALAN BAILEY

Petroleum News

The Federal Energy Regulatory Commission has issued a final environmental impact statement for the proposed development of a hydropower system at Grant Lake on Alaska's Kenai Peninsula. The agency is proposing that the development should proceed, but with some adjustments to the development and operations plans.

Kenai Hydro LLC, a subsidiary of the Alaska Electric and Energy Cooperative, the business entity that operates power generation and transmission facilities as a part of Homer Electric Association, is proposing to build the hydropower system to help meet Homer Electric's goal for the use of renewable energy in the utility's power generation mix.

Grant Lake is an L-shaped water body in the hills above and to the east of the Seward Highway, where the highway runs through the valley of Moose Pass, with Grant Creek flowing from Grant Lake into Lower Trail Lake, just south of the southern end of Upper Trail Lake. Construction of the 5-megawatt hydro facility would involve diverting water from Grant Lake through a tunnel to a powerhouse near the outlet of Grant Creek canyon, a natural rock canyon.

Concerns raised

The project has raised numerous concerns about possible impacts on the Kenai River watershed. The historic Iditarod Trail from Seward to Nome also passes through the project area, a situation that has required discussions over any conflicts with the trail route.

The EIS comments that the proposed power plant would meet part of Alaska's power requirements while also providing some resource diversity.

"We conclude that power from the Grant Lake project would help meet a need for power in the Railbelt region in both the short- and the long-term," the EIS says. "As a renewable resource, the project may provide power that displaces generation from non-renewable sources. Displacing the operation of non-renewable facilities may avoid some power plant emissions, thus creating an environmental benefit."

Cumulative impacts

But FERC also recognized some cumulative environmental impacts that would result from the implementation of this project in addition to existing activities in the basin of the Kenai River on the Kenai Peninsula. Those activities include mining in the Grant Creek watershed, the operation of the Cooper Lake hydroelectric project on a tributary of the Kenai River, and a proposal by the National Forest Service to construct a section of the Iditarod Trail in the area of the proposed hydropower system.

And clearly the system would have impacts on the natural environment in which it would be built. However, the EIS also comments that, while salmon and other fish species spawn in the lower reaches of Grant Creek, impassible falls in the creek prevent anadromous fish from reaching Grant Lake.

In assessing the project FERC considered the project, as proposed by Kenai Hydro, and two alternatives involving modification to that proposal, as recommended by FERC staff. FERC also considered a no-action alternative, in which the development would not be allowed to move forward.

Staff recommendations

Among the staff recommendations are a suggestion not to include a fishery monitoring plan that Kenai Hydro had proposed, and a view that construction of the hydropower system would not require a rerouting of the Iditarod Trail. Other recommendations include modifications to the construction plans, changes to the procedures for plant operation and modification to the plan for taking account of historic properties.

FERC is recommending that the project should proceed, based on Kenai Hydro's plan with some staff modifications and additional measures. ●

Contact Alan Bailey at abailey@petroleumnews.com

continued from page 4

CINGSA TARIFF

lead to a reduction in the facility's rates. Moreover, a more accurate understanding of the facility's injection and withdrawal capabilities would enable customers to better ensure adequate gas storage support for their operations, the RCA said.

Lack of transparency

The RCA also questioned provisions within the tariff, allowing CINGSA to make decisions regarding what services to make available at any particular time, based on CINGSA's internal understanding of its facility's performance capabilities. Those provisions were appropriate at the time of the facility's inception but, with seven years of operational history behind it, CINGSA knows enough about the facility's performance characteristics to publicly post its capabilities in its tariff. That would enable customers to determine storage availability without having to disclose to Enstar, via CINGSA, potentially sensitive competitive information, the RCA said. Moreover, both existing and new gas producers would then have better insights into the possibility of being able to sign up for firm gas storage services, the RCA said.

A similar lack of transparency regarding the availability of capacity for providing some other services creates the potential for discrimination in the provision of these services while inhibiting customers from noticing possible discrimination. Enstar, on the other hand, has full access to the information it needs to make commercial decisions, the RCA said. However, the agency emphasized that it is not accusing CINGSA of actually engaging in discriminatory conduct.

The RCA also questioned a lack of provision in the CINGSA tariff for the temporary release of firm gas storage capacity for a customer who has a temporary need for that capacity. The absence of this provision is economically inefficient and differs from normal practice as regulated by FERC, the RCA said.

CINGSA needs to provide its best understanding of what expansion to its services may be available, and to clarify reasonable terms for an expansion request, the RCA suggested.

Facility expansion

The RCA questioned provisions in the tariff giving CINGSA the right to decide on whether to expand it facilities in response to a customer request. By statute, RCA has the authority to require a facility expansion, depending on the circumstances. And, now that the geology of the facility is well understood and CINGSA knows that it can expand the facility's capabilities, there is no longer any rationale for the existing expansion rules in the tariff, the RCA suggested. The agency also questioned a provision in the tariff, under which a customer could have to reimburse CINGSA for upgrade costs associated with additional services.

CINGSA needs to provide its best understanding of what expansion to its services may be available, and to clarify reasonable terms for an expansion request, the RCA suggested.

The RCA also raised some other specific issues in the CINGSA tariff, including provisions relating to the timing of rate changes, the relative priorities of certain services, the charging of additional fees for service overruns, and some questions regarding definitions. ●

Contact Alan Bailey at abailey@petroleumnews.com

GOVERNMENT

DNR recruiting for DO&G director position

The Alaska Department of Natural Resources is recruiting for the position of director of the Division of Oil and Gas.

The previous director, Chantal Walsh, resigned in February, effective March 1, to return to Petrotechnical Resources of Alaska, a consulting firm she and her husband Tom Walsh co-founded in 1997.

Jim Beckham, deputy director of the division, was named acting director following Walsh's departure.

Dan Saddler, DNR legislative liaison/communications director, told Petroleum News in a March 5 email that Beckham would serve as acting director; he said the recruitment process for a director would probably begin within a few weeks.

"Until the permanent job is advertised and recruitment begins, I can offer no thoughts on whether he is interested in, or being considered for, the permanent job," Saddler said.

Walsh, a lifelong Alaskan, joined the division as director on Nov. 28, 2016, with more than 32 years of private-sector experience in Alaska's petroleum industry. Prior to co-founding PRA, Walsh worked for Standard Alaska Production Co. beginning in 1985, and later for BP and ARCO.

Beckham, known for his organizational skills, attention to detail, hard work, willingness to be a team player and sense of humor, is a graduate of the U.S. Coast Guard Academy with a Bachelor of Science degree in marine science. Following his Coast Guard career, Beckham was vice president of operators for Harbor Enterprises for more than 10 years, and then managed planning and support services for the startup of the nonprofit Alaska Maritime Prevention & Response Network.

The recruitment notice says applications are required by May 24; educational requirements include a college degree in petroleum engineering or geoscience with a post baccalaureate degree in resource management or law preferred.

The notice says the successful candidate will demonstrate "excellent skills and work experience with:" Alaska oil and gas issues; technical aspects of oil and gas exploration and development; Alaska Statutes; strong project management; outstanding communication skills; and strong negotiation and problem-solving skills.

—PETROLEUM NEWS

● EXPLORERS PREVIEW

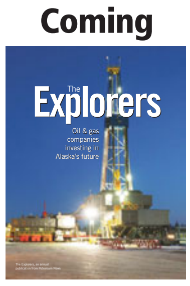
Jade cuts deal to drill Sourdough

First new well in eastern North Slope prospect along 1002 border scheduled for early 2020, ExxonMobil keeps 2% overriding royalty

By KAY CASHMAN
Petroleum News

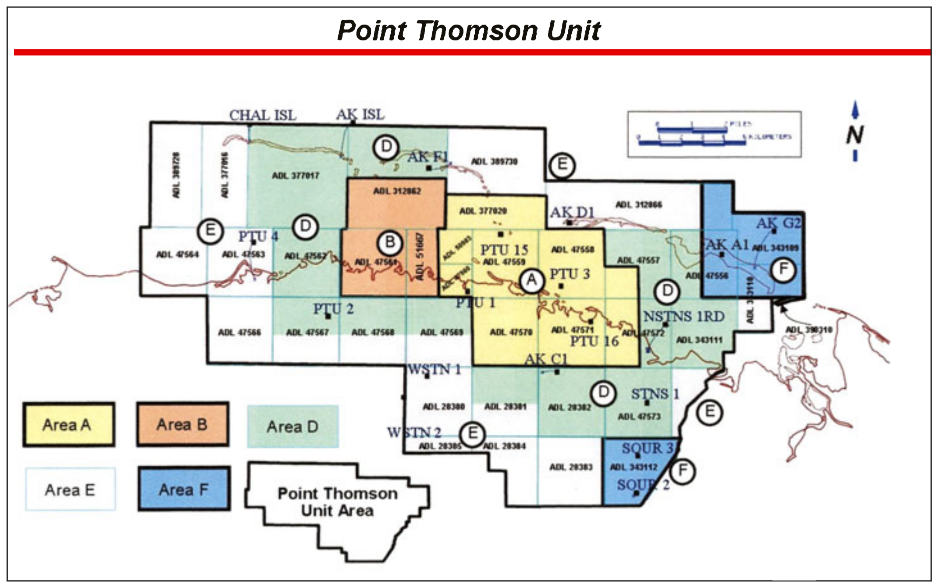
For years industry observers saw production at the untapped Sourdough oil discovery on state land next to the border of the Arctic National Wildlife Refuge as key to opening ANWR's 1002 area to oil and gas exploration and development because geologists thought the Sourdough oil pool ran under the border. The court-tested "rule of capture" law would have allowed a landowner such as the state of Alaska and its lessees to drill on a state Sourdough lease and have the right to what that drilling produced, even though it might be drained from adjacent, undrilled, federal land.

Coming



May 26, 2019

While the Trump administration took the first step by planning two 1002 lease sales, the first targeted for October 2019, it now appears a new Sourdough well and its approved state plan of development could be even closer to tapping federal oil, with the well scheduled for early in the winter of 2020.



JADE ENERGY

The Sourdough lease and its two mid-1990's BP discovery wells lie in the North Slope's Point Thomson unit. In November 2018, PTU operator ExxonMobil assigned a 63% working interest in ADL 343112's Tract 32 to Alaska-based independent Jade Energy LLC, retaining a 2% overriding royalty.

This most southeasterly PTU lease with the legacy Sourdough discovery wells runs along the western edge of the 1002 area, which is a narrow strip of coastline set aside for potential development by Congress because of its hydrocarbon-rich geology.

Sourdough is estimated to hold 100 million barrels of recoverable oil, per a 1997 BP press release.

Minor POD problems

In its justification for requesting the divided interest assignment, Jade told Alaska Department of Natural Resources' Division of Oil and Gas it would "pursue drilling operations on the newly-created segment, as part of a farm-out agreement" with ExxonMobil, then-Division Director Chantal Walsh wrote in a Nov. 13, 2018, letter, noting Jade would also become a party to the Point Thomson Unit Agreement.

According to state Division of Corporations filings, Jade's members and managers are Anchorage-based Erik Opstad and Castle Rock, Colorado-based Greg Vigil, who each owned 50% of the company.

Opstad, who oversees Jade's operations in Alaska, is a state of Alaska certified professional geologist who has worked the North Slope for 34 years, including a stint with BP in various roles and as a principal and general manager of Savant Alaska.

The new plan of development, or POD, proposed for ADL 343112 was spelled out in the two-year Point Thomson Unit 2018 Area F POD, submitted Dec. 21, 2018, to the division by Jade. Although Walsh formally told the unit working interest owners — ExxonMobil, BP, ConocoPhillips, Colt and Jade — in a Dec. 27 letter that the POD "as submitted" was incomplete, "in no way triggers the release of Area F acreage." She said Dec. 21, "remains the date of submittal" for purposes of the Point Thomson Unit Settlement Agreement with the state, which dates back to March 29, 2012.

ERIK OPSTAD

In other words, the Dec. 21, 2018, submittal satisfied the requirement that a POD be submitted for Area F before year-end 2018, per the unit's settlement agreement, even though the submittal was deemed incomplete.

Jade submitted an amended POD on Jan. 24, 2019, which the division deemed complete on Feb. 4, 2019. Jade provided a technical presentation on the POD on March 4, 2019, and submitted amended versions of both the public and confidential portions of the POD on March 19 and March 29, 2019, respectively.

An April 4, 2019, a division decision signed by James Beckham, acting director, approved the 2019 Area F POD for a period of one year.

More wells possible in 2020-21

Beckham noted that Area F consists of approximately 7,647 non-adjacent acres in the northeastern and southeastern corners of the PTU, reiterating that Jade was majority owner and operator of PTU Tract 32, ADL 343112 in the southeastern portion of Area F.

Based on analysis of the appraisal well data, he said, Jade "will move forward accordingly with additional development at Area F and adjoining areas in the 2020–2021 winter drilling season. Current plans include drilling an additional lateral into the Brookian reservoir and production testing. The need for additional delineation wells and the overall economic feasibility of a field development program at Area F will be considered following the 2020–2021 season."

Proposed early 2020 drilling

The POD turned in by Opstad called for targeting Brookian oil reserves, which was the kind of play found in the Sourdough prospect discovery wells.

Within the PTU, Brookian reservoirs were "generally interpreted as amalgamated lowstand channel fill and basin-floor fan deposits," the POD said, pointing out that "typically" these reservoir sands in the area were "predominantly" found onshore at depths between 11,000 feet and 12,000 feet true vertical depth, TVD.

New seismic 3-D data was acquired over the Sourdough area by Jade during the 2017-18 winter season, which the company was having evaluated, per the POD.

Jade was also "seeking to access additional seismic data and has engaged a well-known consultancy to assist interpreting

see EXPLORERS PREVIEW page 9

continued from page 8

EXPLORERS PREVIEW

that data."

When that work was finished the company said it would select an "optimized" well location "to further evaluate the deliverability of the Brookian reservoir," and further delineate "both the vertical and areal extent of the oil accumulation."

The well would be drilled in the first quarter of 2020 and access to the well site would require construction of an ice road. Jade told the division in updated filings it would utilize existing PTU infrastructure to conduct its operations, per an agreement with PTU operator ExxonMobil.

The company intended to gather data from the vertical pilot hole, such as mechanical drilling parameters, LWD data, wireline logs, sidewall and conventional cores, VSP and check-shot information or drill stem test data, the POD said.

Such information would be "used to determine the suitability of the encountered stratigraphic reservoir section for horizontal well construction. Jade feels that that the deployment of horizontal production wells is a critical element in commercializing the Point Thomson unit Brookian opportunity in Area F, as well as its adjoining areas," the POD said.

"Once a vertical pilot hole is drilled, the well will be plugged back and drilled at a high angle into the Brookian reservoir for completion and an extended production test. Production data gathered at this time would be used to analyze the economic viability of a field development program," per the POD.

At the conclusion of this evaluation the well would be plugged and abandoned or suspended.

Upon completion of drilling and extended production testing, analysis of the data "will be integrated into the Jade 3-D Brookian seismic model."

With those results in hand, a second POD would be prepared and submitted by Jade to the division by Dec. 1, 2020.

Work done to date

As part of the development plan Jade outlined work done to date, noting the Brookian reservoir in Area F had been delineated and characterized by five wells that were drilled in and around the Point Thomson unit since the mid-1970s.

Three of the wells were in the northeast corner of the unit and were summarized as follows in the POD:

- Alaska State A-1 on ADL 047556 was drilled by Exxon and reached a 14,206-feet TVD in September 1975 and was plugged and abandoned. That data was available to the public from the Alaska Oil and Gas Conservation Commission, or AOGCC.
- Alaska State A-2 is immediately adjacent to Alaska State A-1 and was drilled as a cutting's disposal well by Exxon in 1995 to 2,364-feet TVD and was plugged and abandoned in March 2002.
- Exxon spud Alaska State G-2 from ADL 343110 and directionally drilled the well north to reach a bottom-hole at 14,340-feet TVD within ADL 343109 in August 1983. The well was subsequently plugged and abandoned, but AOGCC granted the well extended confidentiality.

The other two wells that characterized Point Thomson's Brookian reservoir were Sourdough 2 and 3 and were summarized as follows in Jade's POD:

- BP drilled Sourdough 2 to 12,562-feet TVD in March 1994 and the well was plugged and abandoned.
- In 1996, Sourdough 3 was drilled by BP reaching 12,475-feet TVD in March 1996. The well was suspended. AOGCC granted both wells extended confidentiality.

EXXONMOBIL ALASKA

The export pipeline from the Point Thomson field has the capacity to handle up to 70,000 barrels of liquids per day but can be expanded.

Vintage seismic

Various 3-D seismic surveys have been acquired and interpreted over acreage in Area F, including: Point Thomson 3-D in 1989, 70 square miles, with Exxon the operator; Yukon Gold 3-D in 1994, 95 square miles, with BP the operator; and Mammoth 3-D in 1997, 13 square miles.

"Generally speaking, the quality of all these data sets are good and they have been used by the working interest owners to gain a broad overview of the Point Thomson unit Brookian reservoir," the POD said.

Jade has had "access to the Point Thomson 3-D volume and has used that data set to help it characterize the Brookian opportunity at Point Thomson as well."

Stringing the pipeline pearls

A topic of conversation about the Eastern North Slope over the years has been the importance of Point Thomson and its pipeline infrastructure that connected it with the Badami line to the west and ultimately to the trans-Alaska oil pipeline at Pump Station No. 1.

Point Thomson was the most important pearl in a string of prospects between the central North Slope and the border of the 1002 area.

The pipeline infrastructure was especially important to leaseholders with undeveloped oil prospects farther east than Point Thomson, such as Sourdough, Yukon Gold, Stinson and ultimately any future activity in the ANWR 1002 area.

As of March 31, 2019, the PTU line was capable of shipping 70,000 barrels of liquids per day, but could be expanded, PTU owners have said. ●

Contact Kay Cashman at publisher@petroleumnews.com

UTILITIES

Bill for electric reliability organization

House Bill 151, a bill that would ensure Regulatory Commission of Alaska authority over an electric reliability organization, has been introduced in the Alaska Legislature. The bill was referred to the House Energy Committee and was discussed during a May 9 meeting of the committee. During the meeting, RCA Commissioner Robert Pickett reviewed the issues that the bill is intended to address. The bill will be picked up again in January in the next legislative session.

The commission sees the establishment of an ERO, to oversee the operation of the Alaska Railbelt electrical system and to mandate the use of a consistent set of reliability standards, as the cornerstone of moves toward a more unified approach to system operation. And the Railbelt electric utilities have proposed the formation of the Railbelt Reliability Council, an entity that would act as an ERO.

The commission sees the establishment of an ERO, to oversee the operation of the Alaska Railbelt electrical system and to mandate the use of a consistent set of reliability standards, as the cornerstone of moves toward a more unified approach to system operation.

But the commission worries about its statutory authority to regulate an ERO and has floated potential statutory language to deal with this problem. HB 151 is based on that language. In particular, the commission is concerned about its authority to regulate an entity that would, in turn, have authority over multiple utilities. In addition, the commission, although having ultimate authority over reliability standards, would delegate the management and enforcement of those standards to the ERO. The commission also seeks statutory authority over resource planning in the grid and over the pre-approval of major additions to the electrical system.

The potential statutory language has been discussed during recent RCA public meetings — it appears that there are still some definitional issues that need to be clarified, presumably leading to some further work on any bill designed to address the commission's concerns.

—ALAN BAILEY

EXPLORATION & PRODUCTION

US drilling rig count drops 2 to 988

The number of rigs drilling for oil and natural gas in the U.S. dropped by two the week ending May 10 to 988.

A year ago the count was 1,045 active rigs.

Houston oilfield services company Baker Hughes reported that 805 rigs targeted oil (down two from the previous week) and 183 targeted natural gas (unchanged).

The company said 71 of the U.S. holes were directional, 872 were horizontal and 45 were vertical.

The California rig count was up three from the previous week and Oklahoma was up by two.

Pennsylvania was up by one rig, as was Texas, the most active state, with 485 rigs.

Alaska, Colorado, Ohio, Utah and West Virginia were unchanged from the previous week.

Louisiana and North Dakota were each down one rig from the previous week.

Wyoming was down two rigs and New Mexico was down four.

Baker Hughes shows Alaska with nine active rigs, compared to eight a year ago.

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

—PETROLEUM NEWS

continued from page 5

IEA REPORT

investment in 2018, but IEA says it expects a marginal decline, to 24%, this year "as the reduction of investment anticipated by shale pure operators is only partially compensated by rising spending in sale basins announced by some of the majors."

Diverging trends in US

Over the last 10 years the U.S. share of global upstream spending has risen from 17% to 24%, the report says. IEA expects this trend to be checked in 2019.

U.S. independents have divergent investment strategies, with increased demands for capital discipline and investor returns capping spending by independents, especially for those operating exclusively in shale plays. But a large inventory of drilled but uncompleted wells will likely allow continued robust production, the report says.

International oil companies, on the other hand, have maintained or increased upstream U.S. plans.

"Exxon and Chevron have made the Permian Basin a centerpiece of their strategies, while Shell and BP are increasing their positions," giving majors a greater role in U.S. supply and possibly encouraging further consolidation.

IEA said 2019 is on track to be "the first year where investment growth in shale assets passes from independents to big oil companies," something the report calls "a remarkable change" for an industry sector which has been dominated by smaller companies.

The report notes that since the 2014 downturn the industry has moved away from large, capital-intensive projects with long lead times, in favor of fast-tracking smaller projects or dividing larger projects into phases.

Changing trends

The report notes that since the 2014 downturn the industry has moved away from large, capital-intensive projects with long lead times, in favor of fast-tracking smaller projects or dividing larger projects into phases.

"Lead times for new projects have fallen sharply," the report says.

The move to smaller, standardized projects, has a "strong accompanying focus on efficiency and capital discipline," but also means the industry is increasingly relying on assets with a quick cash flow but faster depletion, which could increase market volatility.

Exploration investment is set to rise to $60 billion in 2019, up 18%, the report says, although the share of exploration in total upstream spending "remains almost half the level in 2010."

Companies were reducing exploration spending even before the 2014 oil price collapse, a trend accelerated by the price drop, with exploration spending dropping by almost half between 2014 and 2018.

The report says companies are expected to continue to keep exploration under close control this year, but "the anticipated increase would be the first one since 2010."

As with other sectors of the industry lower funding has "driven the deployment of more efficient rigs and a decline in the cost of seismic surveys, ultimately leading to an overall reduction in the average project break-even."

The reduction in exploration activities also resulted in "a massive reduction in discovered resources," the report says, with an average of 5.2 billion barrels of oil equivalent of conventional discoveries annually between 2014 and 2018, two-thirds lower than the average over the previous decade, with a similar trend in natural gas discoveries. ●

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ALBERTA ALARM

The overall impact can be easily measured by empty office towers in downtown Calgary, where vacancies are estimated at 25%.

Canary in the coal mine

But it has taken the failure of Trident Exploration, a privately held small company — the canary in the coal-mine — to capture the public attention and focus on the scope of the industry's woes.

What Trident also blames for its downfall was a Supreme Court of Canada ruling in January affecting insolvent Redwater Energy that ensures environmental cleanup costs faced by taxpayers must get priority over creditors when companies go bankrupt.

That adds to a tsunami of orphaned oil and gas wells in the past five years, with the latest numbers estimating 3,127 wells need to be plugged or abandoned and a further 1,553 that have been abandoned and need to be reclaimed.

At the time it ceased operations on April 30, Trident was producing 67.5 million cubic feet equivalent per day of gas from proved reserves of 458 billion cfe.

The company announced it was terminating 33 employees and contracts with 61 companies after failing to secure approval of the Alberta Energy Regulator (a provincial government agency) "for a restructuring in a timely fashion."

As a result, 3,358 operating wells, 294 abandoned wells, 502 pipeline licenses, 211 operating facilities and 27 abandoned facilities carrying remediation costs of C$259 million have been turned over by Trident to the AER.

CAPP view

Brad Herald, a vice-president with the Canadian Association of Petroleum Producers, said many if not most of the wells are likely to be sold, adding "there may be somebody who is better financed or has a longer view to overcome some of the short-term tumult."

Looking at the bigger picture, he said the credit industry is "evolving the way it looks at risk," adding that CAPP was expecting an increase in defaults because of that evolving assessment.

"Ultimately, the Redwater decision, regulatory uncertainty and a lack of egress has created a treacherous environment for energy investors that dare to risk their capital in Canada," Trident said.

"As many have speculated and we have now unfortunately proven, the Redwater decision has had the unintended consequences of intensifying Trident's financial distress and accelerating unfunded abandoned well obligations.

"We fear that many other companies may falter without clear, sound policy-making post-Redwater. In the face of this extended uncertainty, lenders and investors may flee Canada and further job losses will occur," the company warned.

Orphan wells

The Alberta Orphan Well Association, OWA, an industry-funded organization which pays for cleanup costs from a levy paid by all energy companies, faces the daunting if not impossible task of grappling with Alberta's 90,000 idle wells, most of whose owners are no longer solvent.

Since the industry downturn five years ago, the number of oil and gas sites that no longer have solvent owners has soared to 4,349.

The only shred of hope is to transfer as many wells as possible to other companies to keep them working and contributing royalties to the provincial government.

The AER estimated the cost of reclaiming land disturbed by oil sands mines will cost C$27 billion, although internal AER documents have pegged the bill at closer to C$100 billion, compared with the mere C$900 million the province holds in security.

Although many view oil sands companies as the most responsible element of the industry, the fate of smaller conventional operators is less comforting.

A spokesman for surface rights organizations which work with small energy companies said the situation is "going to get a lot worse. There are close to 31 companies right now that are close to going insolvent."

The OWA took the "unprecedented" step earlier in May of having a receiver appointed to manage Trident's assets.

"Normally, the company or its creditors would clean up its sites or appoint an insolvency professional to help transition the licensed assets, where possible, to other parties," the OWA said.

"In this case, the OWA had no other choice but to take this step to ensure that Trident's assets are managed and maintained safely for the benefit of the public and where possible, placed in the hands of responsible operators." ●

Contact Gary Park through publisher@petroleumnews.com

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TRANS MOUNTAIN

All he would pledge was to continue "engagement" with First Nations "in a meaningful two-way dialogue to ensure our constitutional obligation (to consult with indigenous communities) is met."

Sohi said he is ready to work with Alberta's new Premier Jason Kenney in a "shared goal of ensuring we are working hard on behalf of Albertans on a shared goal to grow the economy to create jobs and to move forward in getting our resources to global markets."

Collision course

That thinking could put him on a collision course with his own cabinet colleague, Environment Minister Catherine McKenna, who issued a tweet after federal Opposition leader Andrew Scheer met with petroleum industry executives.

She said Scheer had been "caught scheming behind closed doors with wealthy executives to gut environmental protection laws, silence critics and (remove penalties on) pollution."

Without making any direct reference to TMX, McKenna side-stepped the fact that most leaders of Canada's largest oil and gas producers — Suncor Energy, Canadian Natural Resources, Shell Canada and Cenovus Energy — backed the former Alberta government's plan to set a cap of 100 million metric tons a year on oil sands emissions and impose a provincial carbon tax.

For now, Sohi continues to go through the motions of "engaging" with First

see **TRANS MOUNTAIN** *page 13*

Wolfpack Land Company is Offering 4,761 Acres of Prime Mineral Interest Ownership in the Kenai, Alaska Area for Oil and Gas Leasing

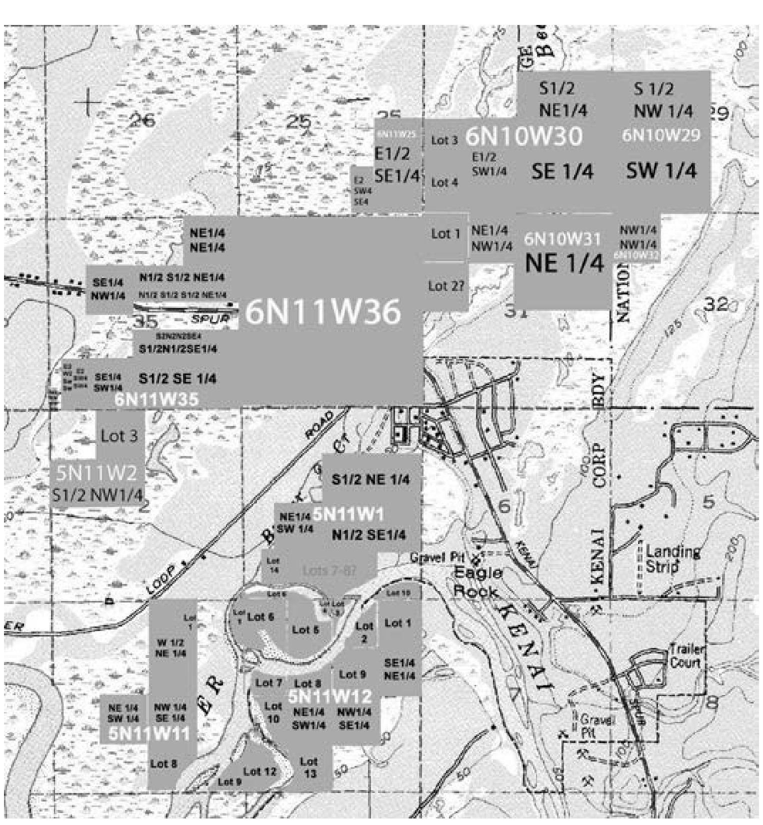
Beaver Loop Road Area

Township 5 North, Range 11 West (Surveyed)
Section 1, Lots 6-8, 10, 14, S1/2NE1/4, N1/2SE1/4, NE1/4SW1/4;
Section 2, Lots 3 and 6, Sl/2NW1/4.
Section 11, Lots 1, 8, 9, W1/2NE1/4, NW1/4SE1/4, NE1/4SW1/4;
Section 12, Lots 1-13, NE1/4SW1/4, SE1/4NE1/4, NW1/4SE1/4.
Containing 1,063.51 acres, more or less.

Township 6 North, Range 10 West (Surveyed)
Section 29, SW1/4, S1/2NW1/4
Section 30,Lots 3 & 4, E1/2SW1/4, SE1/4, S1/2NE1/4
Section 31,Lots 1 & 2, NE1/4NW1/4NE1/4
Section 32,NW1/4NW1/4
Containing 947.98 acres, more or less.

Township 6 North, Range 11 West (Surveyed)
Section 25, El/2SE1/4,El/2SW1/4SE1/4
Section 35, NE1/4NE1/4, N1/2S1/2NE1/4, N1/2S1/2S1/2NE1/4, SE1/4NW1/4, E1/2SW1/4SW1/4, E1/2W1/2SW1/4SW1/4, W1/2SW1/4SW1/4SW1/4, SE1/4SW1/4, S1/2SE1/4, S1/2N1/2N1/2SE1/4, S1/2N112SE1/4.
Section 36,All
Containing 1,105 acres, more or less.

Aggregating 3,116.49 acres, more or less.

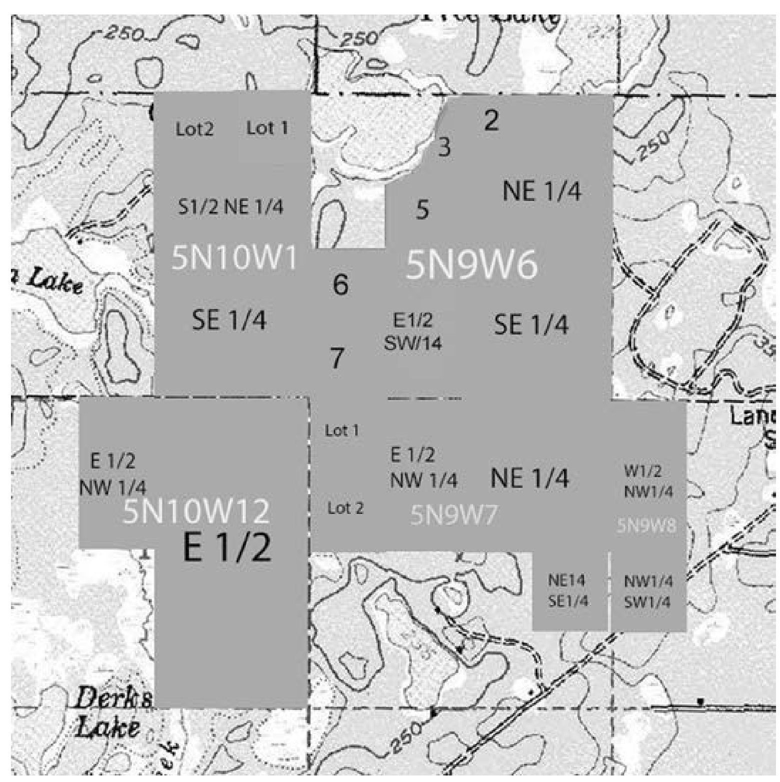


Robinson Loop Road Area

Township 5 North, Range 9 West (Surveyed)
Section 6, Lots 2, 3, 5-7, SW1/4NE1/4, El/2SWl/4, SEl/4;
Section 7, Lots l, 2, El/2NWl/4, NEl/4, NEl/4SEl/4;
Section 8,Wl/2NW1/4, NWl/4SWl/4.
Containing 926.23 acres, more or less.

Township 5 North, Range 10 West (surveyed)
Section l, Lots l, 2, Sl/2NEl/4, SEl/4;
Section 12, El/2, El/2NWl/4.
Containing 718.96 acres, more or less.

Aggregating l,645.19 acres, more or less.



These fee mineral rights have significant known hydrocarbons on or very near them. This prospect is not in a remote area. Everything is road accessible, winter and summer, with easy access to oilfield suppliers. Seismic data available.

Terms: $3,000/acre, 25% royalty.

For more details contact Wolfpack Land Company, Houston, Texas, at jim5thgn@outlook.com, jim@applecapital.net, or (907) 394-9148.

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RCA AGENDA

utility consolidation. MEA told the commission that it will be impacted because of the interconnections between MEA's system and the two Anchorage utilities. The commission is also allowing Providence Health and Services to intervene — Providence is a major ML&P customer.

A chain of events

The idea of having Chugach Electric purchase ML&P, to form a consolidated utility in Anchorage, was first announced in December 2017. The idea is to achieve long-term cost savings and efficiencies by eliminating the duplication of functions and through the more efficient use of power generation resources. In April 2018 Anchorage voters approved the concept. In October 2018 the parties involved agreed on the terms of the sale. In December 2018 the Municipality of Anchorage approved the sale. Then, with the Chugach Electric board already having approved the deal, the parties moved ahead with preparing RCA filings, seeking the relevant approvals from the commission.

Chugach Electric and the municipality hope to complete the deal in the fourth quarter of 2019 or early in 2020.

Complex deal

The deal is complex and involves several major components: an upfront payment to close the deal; payments in lieu of taxes to the Municipality of Anchorage by Chugach Electric for a period of 50 years; and a commitment to purchase Eklutna hydroelectric power from the municipality for 35 years. And the proposed manner in which the businesses of the utilities would be combined reflects a commitment that the electricity rates of the two utilities would not immediately be impacted by the deal, although in the longer term rates are anticipated to be lower than they would be without the deal going ahead.

A complication arises from the fact that both Chugach Electric and ML&P own portions of the Beluga River gas field on the west side of Cook Inlet and obtain some of their power station fuel gas from that field. The prices that the two utilities pay, in effect for their own gas, differ with the ML&P gas being cheaper.

HEA and GVEA concerns

In its petition to intervene HEA expressed concern that the merger of the two utilities would remove a participant from the Railbelt wholesale market for economy energy sales and spinning reserves, with possible impacts on wholesale power pricing. Economy energy sales involve the sale of attractively priced power from one utility to another.

In addition, HEA said that the combined utility would end up owning more that 50 percent of the rights to power generated by the Bradley Lane hydropower facility in the southern Kenai Peninsula: These resulting majority rights would give Chugach Electric total control over the scheduling and dispatch of Bradley Lake power, HEA told the commission.

GVEA's concerns particularly focus on the scale of the combined Chugach Electric/ML&P system, and the risks that this scale of operation poses to the Alaska Railbelt system as a whole. Chugach Electric is already the largest utility in the Railbelt, with substantial authority over the electricity system, GVEA told the commission. When the Railbelt system was originally formed. the participants ensured that no one entity had too much authority over strategically important generation and transmission assets, GVEA wrote.

GVEA also commented on possible adverse impacts on economy energy sales across the Railbelt grid.

Three dockets involved

In its May 8 order the commission said that there are actually three active dockets relating to the purchase of ML&P, and that the commission is now consolidating these dockets. One docket seeks assurance of commission approval of the retrieval through electricity rates of Chugach Electric's costs associated with the ML&P purchase, seeks approval for the various components of the deal, and seeks approval of the inclusion of ML&P's service area in Chugach Electric's certificate of public convenience and necessity. The second docket addresses a number of technicalities associated with the deal, including modifications to ML&P's certificate. The third docket involves an investigation into the manner in which ML&P manages the disposition and pricing of its Beluga River field gas.

Hearing schedule

A key issue to be addressed in the first of these dockets is the need to determine whether, given that the price that Chugach Electric proposes paying for ML&P's assets is above book value, the purchase is in the public interest, the commission said.

The commission has scheduled a hearing for the third docket for Aug. 12, potentially through Aug. 21. A combined hearing for the other two dockets will run from Aug. 27, potentially through Sept. 17.

Given the complexity of the issues to be addressed, the commission has contracted consultancy firm Black and Veatch to provide expert assistance in assessing the terms of the ML&P purchase and the likely impact of the purchase on electricity consumers.

—ALAN BAILEY

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TRANS MOUNTAIN

Nations on TMX, noting those discussions have involved 60 federal employees in eight teams working in British Columbia and Alberta.

Faced with the latest extension of the decision-making deadline from May 22 to June 18, and now an unknown date, TMX Chief Executive Officer Ian Anderson said his company can do no more than get "poised to restart the expansion project (from 300,000 barrels per day to 890,000 bpd)."

Others were less tactful, including Matthew Deeprose, chief executive of Vault Pipelines, who said delays in TMX construction make it difficult for contractors and subcontractors to retain workers, resulting in prices creeping up.

One source in the pipeline sector said some subcontractors are mulling over whether they should even retain their TMX work commitments, while Tristan Goodman, president of the Explorers and Producers Association of Canada, said that amid doubts over the federal government's "desire to move forward" with TMX, the setbacks have become "unacceptable."

—GARY PARK

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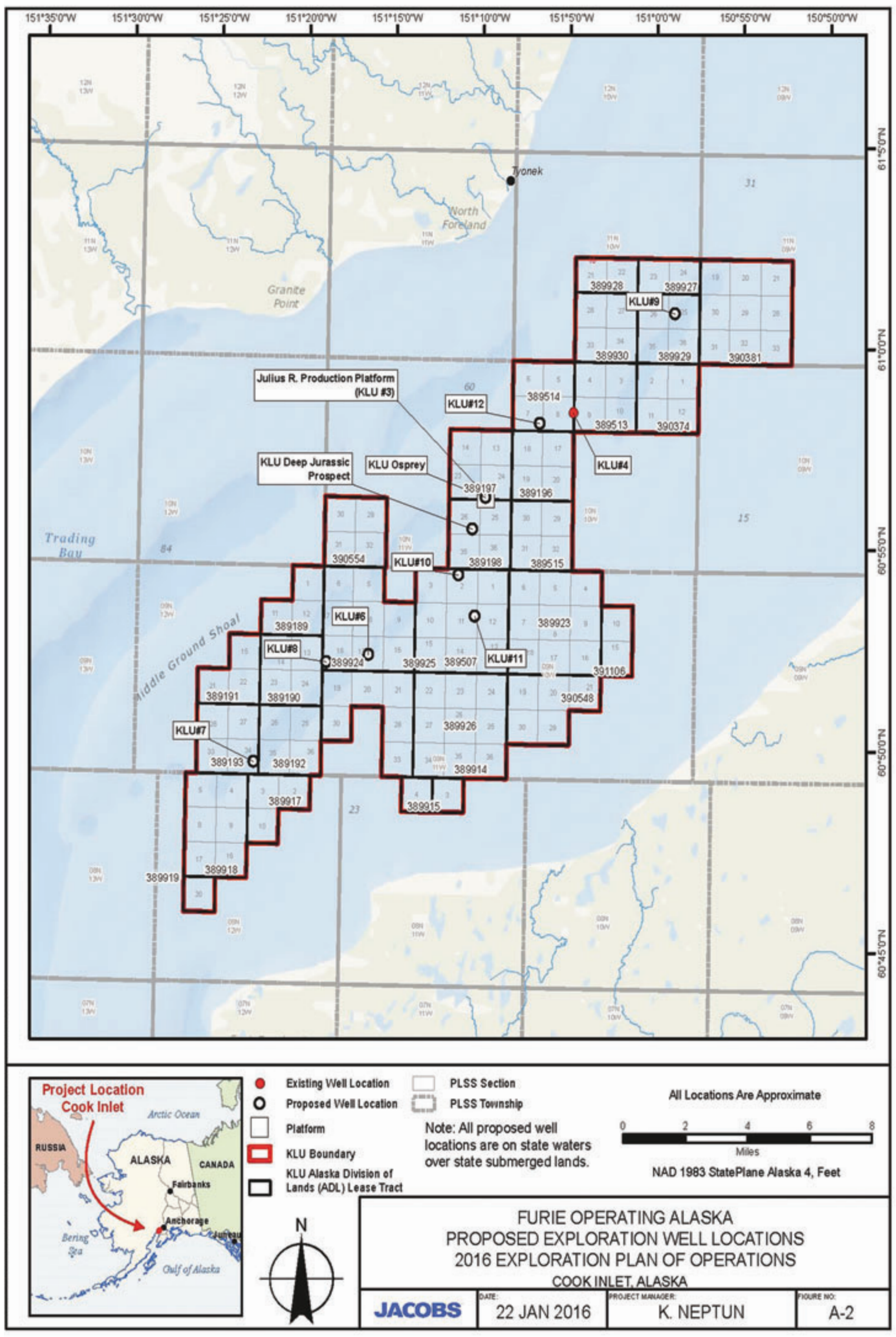

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KITCHEN AUCTION

mentioning Deutsche Oel & Gas, Furie and Cornucopia Oil & Gas Co., the last two listed by the state of Alaska as part owners of Kitchen Lights. (Per its website, Deutsche owns Cornucopia and Furie, listing its primary asset in Alaska as the Kitchen Lights unit)

The May 10 auction was postponed until May 31, the auctioneer in the public notice, Ronald M. Caspert, later told Petroleum News in an email.

Pinsonnault lead

It was not the first-time lender ECP started foreclosure proceedings against owners of the Kitchen Lights unit. Something similar happened in 2018 when an auction was scheduled for April 13 of that year but was cancelled by ECP when a new agreement was presumably put together with the owners.

As part of that deal Furie's leadership changed, with Scott Pinsonnault taking the helm as chief operating officer and Bruce Webb, who had been the company's senior vice president, leaving the company.

According to state records, the ownership of the 83,394-acre unit falls out as follows on the leases and ostensibly for the other assets in the field such as the Julius R offshore production platform, the onshore production facility and subsea pipeline: Cornucopia Oil & Gas Company LLC 78.999%; Corsair Oil & Gas LLC, a subsidiary of Cornucopia 0.001%; A.L. Berry 7.875%; Danny S. Davis (see sidebar) 6.875%; Taylor Minerals LLC 5.25%; and, Furie Operating Alaska LLC 1%.

According to CorporationWiki, League City, Texas-based Corsair Oil & Gas's members are Damon. R. Cade, manager, Trent Kososki, manager, Jeffrey A. Brodsky, independent manager, and Kay Rieck, member/manager. The company was formed in 2014 and currently shows as inactive in Texas.

Rieck is also chairman of Deutsche, per its website, with Webb listed as a board member since December.

Trent Kososki at ECP

Interested bidders were asked to contact Trent Kososki at Energy Capital Partners Mezzanine Opportunities Fund A, LP, c/o Energy Capital Partners, 1000 Louisiana Street, Suite 5200, Houston, TX 77002, fax 713-496-3101, email tkososki@ecpartners.com.

A copy of the query should be sent to Jennifer M. Gray at Energy Capital Partners Mezzanine Opportunities Fund A, LP, c/o Energy Capital Partners, 12680 High Bluff Drive, Suite 400, San Diego, CA 92130, fax 858-703-4401, email jgray@ecpartners.com.

Interested bidders can obtain access to a data room with information about the collateral and sale terms if they enter into a non-disclosure agreement, this year's public notices said.

Bids subject to caveats

The "secured party" referred to in the public notices is presumably the lender, ECP, since it sponsored the advertisements.

The auction, which will be held at the offices of Kirkland & Ellis LLP on Lexington Avenue in New York City (bidding by telephone allowed), is subject to these caveats:

• "The secured party reserves the right to bid, to become purchaser at the sale and, without deposit, to credit against the purchase price any or all sums due to it under the credit agreement and to adjourn, delay or terminate the sale at any time."

• The collateral will be "sold as a block and not be broken down."

• The Alaska Department of Natural Resources must "provide its approval with respect to a change of ownership of the borrowers. … Accordingly, the bidder shall use its best efforts to obtain the DNR approval within 30 days after the auction date." If unsuccessful in getting DNR's approval in that time period, "or otherwise confirmed in writing to the secured party that it will purchase the units without obtaining such DNR approval, by such date, the secured party reserves the right to cancel the sale to the bidder."

• The bidder will be "required to represent that the collateral is being acquired for the purchaser's own account and not with a view to the sale or distribution thereof and that the collateral will not be resold unless pursuant to an effective registration statement under the Securities Act of 1933 … and any applicable state securities laws or under a valid exemption from the registration requirements of the Act and such laws. The bidder will also be required to provide the secured party with an investment letter."

Enstar contract still in effect

But not all recent news is bad.

"We have safely restored utility and communication between our onshore natural gas processing plant and the Julius platform over this past weekend," Pinsonnault told Petroleum News in a March 19 email. He said Furie would spend the next few weeks making sure that the line was completely clear, functional and safe before restoring gas production from the field.

And while the number of producing wells fell from four in December, to three

see **KITCHEN AUCTION** *page 16*

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OIL SEARCH PLANS

which was the Nanushuk, followed by the deeper Alpine.

Subject to regulatory approvals, "we anticipate entering the FEED phase of this exciting new oil development in 2019," Oil Search said; FEED meaning front-end engineering and design.

Construction of the "initial Pikka unit development is planned to commence in early 2020 and take place over three winter construction seasons, with first production expected in late 2023," the company said.

28% women

One new tidbit revealed at the annual meeting was that 28% of Oil Search's Alaska team at the end of 2018 — "more than 100 employees and several contractors" — headquartered in the Anchorage office were women and 75% were Alaska residents.

Earlier this year, Oil Search leased two floors at the BP building in midtown as it had outgrown its space in Peterson Towers in downtown Anchorage. Previously, company executives have said they expected the number of Oil Search employees to increase to approximately 200 once Pikka development got underway in early 2020.

The most interesting information released at the annual meeting was the updated map next to this story that includes the new acreage Oil Search acquired in the last seven months: more than 17,000 acres east of the Pikka unit through pre-existing commercial agreements with Repsol; state leases won at the November areawide oil and gas lease sale covering 3,575 acres immediately adjacent to the northern boundary of the Pikka unit (on the map those two leases are identified as Pikka North); and a 50% interest in a 195,200-acre block on the eastern North Slope purchased from Armstrong, exercising an option under an area of mutual interest agreement.

Alaska "exploration licenses," meaning prospective leased areas, and Oil Search's ownership percentages were identified in a shareholder document as the following: Antigua, 25.5%; Atlas A, 25.5%; Atlas B, 25.5%; Grizzly, 51%; Harrison Bay, 25.5%; Kachemach, 25.5%; Thetis, 25.5%; Horseshoe, 37.5%; Hue Shale, 37.5%; and the Pikka Unit, 25.5%.

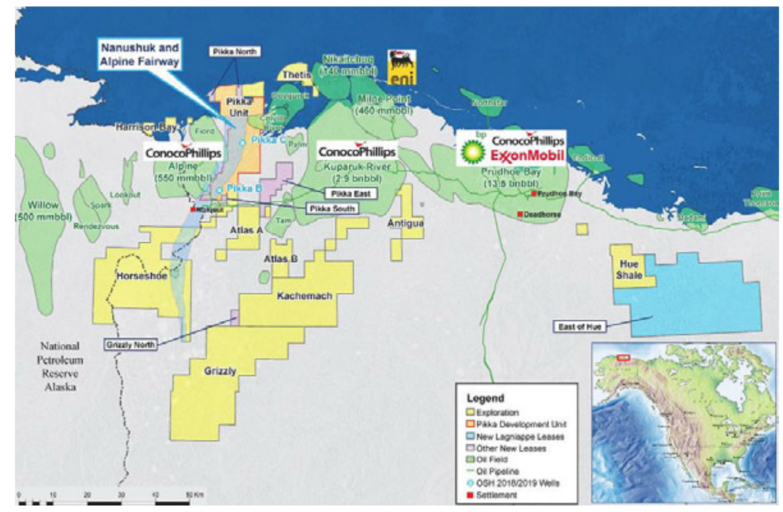
Oil Search has an option through June 30 to acquire an even larger interest in Pikka, Horseshoe and nearby leases. For an additional $450 million, the company can buy Armstrong and GMT Exploration's interests in the acreage, which varies from 25.5% to 37.5%, depending on the lease.

—KAY CASHMAN

OIL SEARCH ALASKA – NOW FULLY ESTABLISHED AND OPERATIONAL

Oil Search

- Alaska acquisition completed Feb 2018, highly experienced team recruited with extensive operating capability
- Successful first drilling campaign recently completed:
  - Pikka B/ST1 reservoir and flow rates above expectations, materially upgrading prospectivity in south of Pikka Unit and Horseshoe Block
  - Pikka C reservoir characteristics in line with forecast but flow rates restricted by mechanical issues/downhole blockages



- Material oil resource upgrade expected above current 500 mmbbl (gross) 2C estimate
- Sufficient data gathered on reservoir deliverability to support plans to move into FEED in 2019

OIL SEARCH 2019 ANNUAL MEETING | 10 MAY 2019 | PAGE 19

Story began with Escopeta


DANNY DAVIS

The history of the Kitchen Lights unit dates back to mid-2009 when the Alaska Department of Natural Resources' Division of Oil and Gas approved creation of the Kitchen Lights unit, combining the Kitchen, Northern Lights and Corsair prospects.

Unit approval was a culmination of efforts by leaseholders and the state over a number of years to find a way to get drilling done on a series of prospects in Cook Inlet, originally held by different leaseholders but by then consolidated with Escopeta Oil Co. under the leadership of entrepreneur Danny Davis.

At that time only one of the prospects, Corsair, had seen a drill bit.

Shell, Phillips and ARCO had drilled exploration wells in the Corsair prospect from 1962 to 1993. Four of the wells targeted oil; one targeted gas. The wells had gas shows — some also tested small quantities of oil.

The Northern Lights prospect, south of the North Cook Inlet unit along the anticlinal trend that connected it with the Corsair structure, was targeting a downdip extension of Tyonek Deep oil reservoirs encountered in most deep North Cook Inlet wells.

"The play depends on the Tyonek Deep sands extending some distance south of the North Cook Inlet unit and still remaining in the oil column," the division said at the time.

Internal changes aside, in 2011 Escopeta was essentially restructured and renamed Furie and came under different leadership.

A major milestone occurred later that year when the company announced the discovery of a large natural gas field during the drilling of the KLU No. 1 well from the Spartan 151 jack-up rig that Davis had brought to Alaska.

—KAY CASHMAN

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KITCHEN AUCTION

part-time in January, and one barely producing in February, by March one of the wells had been put back online and was producing about 25 percent as much gas as it had been in December (68,651 mcf).

At the time this story went to press in May, production was not yet available from the Alaska Oil and Gas Conservation Commission, and as of May 15, Pinsonnault had not replied to Petroleum News' request for the status of natural gas production at Kitchen Lights.

But in a May 13 email, Lindsay Hobson, Enstar communications manager, said that although "Enstar is not receiving firm volumes from Furie at this time," the contract with the independent is "certainly" in effect.

"The parties," she said, "are still in discussions regarding the future of the contract."

Pinsonnault and ECP would not comment on the status of the foreclosure. ●

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PLACER POD

the Placer No. 3 well in the unit. Because of off-road travel restrictions on the North Slope, that testing would have to be conducted during the winter off-road travel season, which was sure to end by May 31.

Following some issues regarding the plans for the well re-entry work, the division approved a revised plan of operations, including the well re-entry, in early March. However, in a Feb. 28 letter to the division, AEX had expressed concern about whether this approval would come in time to conduct the well operations before the end of the off-road travel season. AEX had originally filed an amended plan of operations on Jan. 8, the company said. An industry source has told Petroleum News that the well re-entry was not carried out.

AEX questioned testing requirement

In September AEX had appealed to DNR over the division's original plan approval ruling, both with respect to the nine-month rather than one-year length of the plan, and with regard to the necessity of including the well testing within the plan. AEX claimed the division had no justification for approving a nine-month duration for the plan rather than the 12-months that AEX had requested. Also, AEX said that it had not viewed the testing of the Pacer No. 3 well to be necessary at this stage of the company's plans for the unit, but that the division had insisted on inclusion of the testing in the 2018 plan of development. AEX is continuing to conduct planning and modeling work, designed to bring the Placer unit into production: There is no regulatory requirement to include "on the ground" activities in a plan of development, AEX argued.

The DNR decision

The April 18 decision by DNR was the agency's response to AEX's appeal over the division's plan approval ruling. DNR found that, while there is no legal requirement that a plan of development must cover a 12-month period, the division must provide an adequate justification for the shorter time period. The division had not provided a sufficient justification, DNR said. However, there is no evidence that the division had any particular bias against AEX when making its plan timing decision, DNR ruled.

DNR also agreed with a contention by AEX that state oil and gas regulations do not require a plan of operations for a unit to include "on the ground" activities — a plan simply needs to be geared towards bringing a unit into production. The division may determine that on the ground operations of some form are necessary at some point in the development but, if so, must explain why these operations are needed, DNR ruled.

The division response

The division's May 10 notice responds to the DNR ruling regarding the length of the 2018 plan of development. The division said that it was AEX, and not the division, that had limited the time to complete the Placer No. 3 well testing — AEX had indicated that the testing had to be completed by the end of the winter off-road travel season.

"Thus the division clarified in its 2018 POD approval that AEX would complete the winter operation by May 31, 2019," the division wrote.

However, given the length of time for a ruling on AEX's appeal, the schedule in the original plan of development is no longer feasible and the division is extending the plan until July 10, the division wrote.

The division has yet to respond to the DNR ruling on the need to justify the division's stipulation that the well testing must be included in the plan. ●

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SALSA OFFERING

a.m. Dec. 11 in Anchorage; the notice of sale with terms and conditions will be available in June.

In the presentation the division described this as an opportunity to bid on large, contiguous acreage blocks, groups of North Slope and Beaufort Sea Areawide lease sale tracts that will be offered together.

The division said it "has gathered and highlighted large amounts of publicly available data that bears on the SALSA areas."

Lists of the types of information available are included in the division's presentation on the program.

Each of the lease blocks has 3-D seismic data acquired through the state's tax credit program. The division said the seismic data is available "for a modest fee" through DNR.

The three proposed SALSA blocks are Harrison Bay, Gwydyr Bay/North Shore and Storms.

The division had no takers for the SALSA blocks last year, the first time the blocks were offered.

—KRISTEN NELSON

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