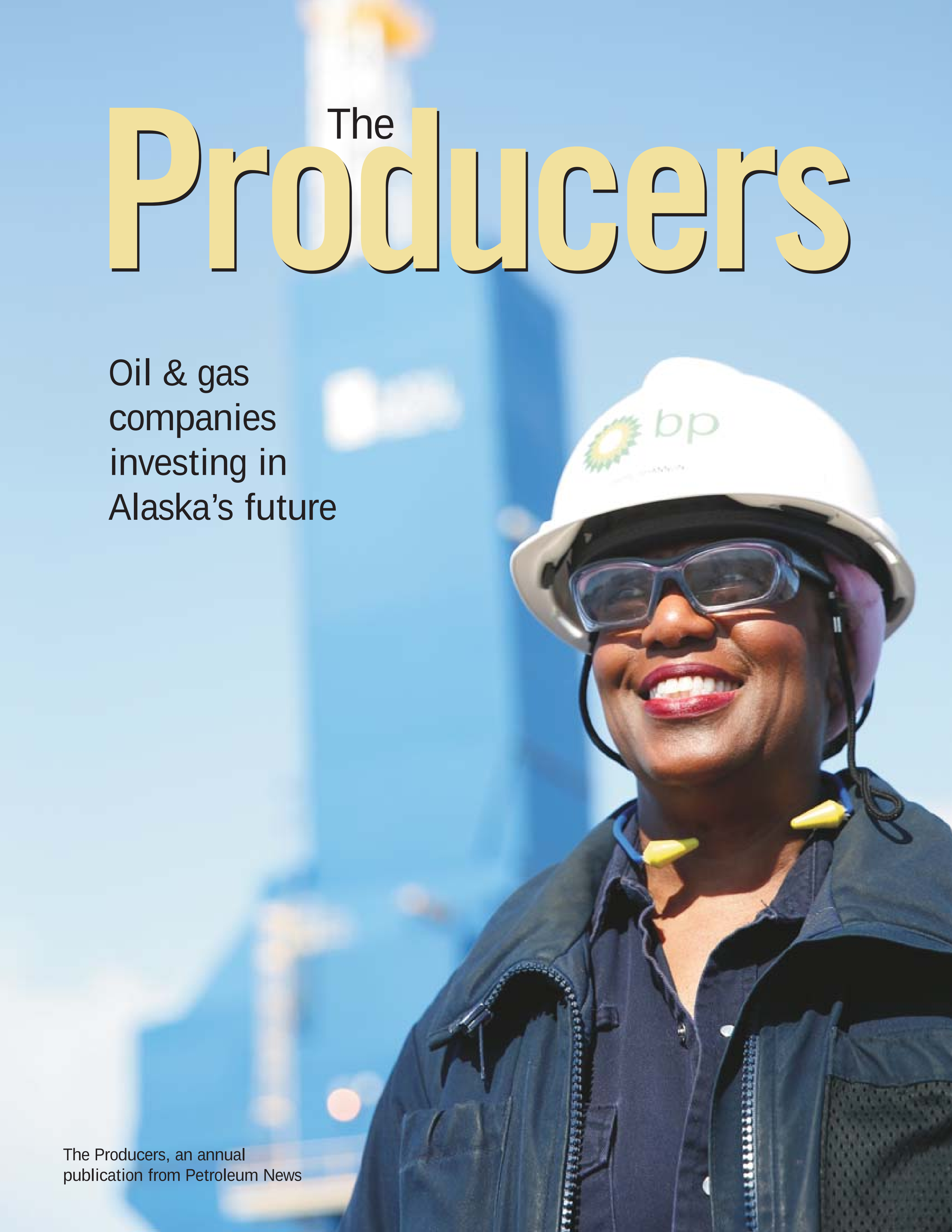

The Producers

Oil & gas companies investing in Alaska's future

The Producers, an annual publication from Petroleum News

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A year of uncertainty for Alaska

Oil prices and tax credits cast a long shadow over the operators profiled in this edition of The Producers

By ERIC LIDJI
For Petroleum News

Putting together The Producers each year usually requires some last-minute revisions, as we try to incorporate the latest development activities and new plans for the year ahead.

This year was more uncertain than most.

As we were wrapping up the issue:

Aurora Exploration was bumping into obstacles in its acquisition of the Nicolai Creek unit through a bankruptcy sale. BlueCrest announced the suspension of drilling activities at Cosmopolitan and later announced a one-well drilling program for 2018. Brooks Range Petroleum Corp. was working to certify an existing well by the end of the year as a way to beat a development deadline. ConocoPhillips was told it could expand the Colville River unit to include the former Tofkat unit. ExxonMobil was told it needed to revise its plans for condensate production at Point Thomson. Furie announced that it had cancelled its drilling program this year in the face of the state budget stalemate over the summer.

Even the less-volatile news carried a tinge of uncertainty to it: BP continues to cut back drilling at Prudhoe Bay. Caelus is approaching the second anniversary of its drilling suspension at Oooguruk. Eni decided to release its long-held rig at Nikaitchuq in favor of workover activities and a federal exploration venture. Glacier announced a fairly cautious program at its properties, with the possibility of exploration.

The steadiest stories came from the least and most prolific players in the state.

The North Slope Borough continues to reap the benefits of its Barrow gas fields. AIX Energy continues to do the same at the Kenai Loop field, although investments may be required soon to maintain production. On the other end of things, Hilcorp continues to advance operations at its wide portfolio on the North Slope and in the Cook Inlet basin.

Connecting many of these stories are two themes: the adjustment to a period of depressed oil prices and the impact of reduced state funding to purchase state-issued tax credits. ●

Connecting many of these stories are two themes: the adjustment to a period of depressed oil prices and the impact of reduced state funding to purchase state-issued tax credits.

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The Producers

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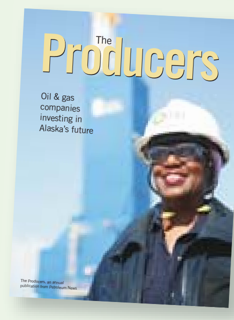
MAILING ADDRESS:
PO Box 231647
Anchorage, AK 99523-1647
Phone: (907) 522-9469
Fax: (907) 522-9583
Email:
circulation@PetroleumNews.com
Web page:
www.PetroleumNews.com

To order additional copies of this special publication, contact Heather Yates, Petroleum News bookkeeper, at hyates@petroleumnews.com

On the cover:
Shirl Shannon has been working for BP as an Instrument Technician on the North Slope for 37 years.

Photo courtesy Judy Patrick



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AIX working within means at Kenai Loop

A new supply contract allows for future production declines and for a possible increase

By ERIC LIDJI
For Petroleum News

NAME OF COMPANY: AIX Energy LLC
COMPANY HEADQUARTERS: 2441 High Timbers Dr.120, The Woodlands, TX 77380
TELEPHONE: 832-813-0900

The history of the Kenai Loop gas field shows how two companies with different philosophies can employ different strategies when it comes to operating a given property.

Since assuming control of Kenai Loop in late 2014, AIX Energy LLC has taken a much more cautious approach than its predecessor — the Australian independent Buccaneer Energy Ltd. — took toward developing the onshore field in the northern Kenai Peninsula.

Over the course of its nearly five-year tenure as operator of Kenai Loop, Buccaneer drilled four wells, bringing the field online in January 2012. The company also secured a series of gas supply agreements and increased production to meet those agreements. But its ambitiousness in the Cook Inlet region yielded a long regulatory battle over correlative rights at Kenai Loop and eventually led the company to file for bankruptcy protection.

By contrast, the Texas-based independent AIX Energy has not drilled any new wells since it acquired Kenai Loop from Buccaneer in an October 2014 bankruptcy auction.

Instead, the company has been focusing on improving existing infrastructure at the field and managing marketing activities. In its most recent plan of development, submitted in May 2017, the company described its strategy as an attempt "to maximize field recovery and net present value by aligning production capacity with commercial opportunities."

Production declining

After several years of steady production, the Kenai Loop field appears to have reached an initial peak. Natural gas production has been declining in recent years. The field produced 3.6 billion cubic feet in 2015, 3.2 billion cubic feet in 2016 and 1.5 billion cubic feet during the first half of this year, for a cumulative total of 16.5 billion cubic feet by the end of June 2017, according to the Alaska Oil and Gas Conservation Commission.

Only two of the four existing Kenai Loop wells are currently in production. The KL 1-1 and KL 1-3 wells together produced 3.159 billion cubic feet of gas in the year ending March 31 — down from 3.657 billion cubic feet during the previous year, according to figures AIX Energy provided in its development plan. The wells also produced 507 barrels of condensate during the reporting year, down from 649 barrels the previous year.

In a previous plan of development, AIX Energy said it was evaluating a plan to re-perforate the existing Kenai Loop No. 1-3 well in order to improve deliverability. The company did not include the project in its most recent plan of development for the field.

At the time AIX Energy submitted its current plan, in early May 2017, the company had at least four gas supply agreements at the Kenai Loop field: a non-firm contract with Tesoro, a non-firm contract with an un-named company (likely Chugach Electric Association Inc., given previous regulatory filings), a firm contract with Tesoro set to expire in early 2018 and a larger firm contract with Enstar Natural Gas Co. set to expire in mid-2018. "AIX has multiple contracts which are likely to lead to additional non-firm sales in 2017. AIX is also pursuing additional firm commitments beyond the termination of the Tesoro and Enstar contracts in 2018," AIX Energy wrote in its development plan.

This past summer, Enstar requested regulatory approval for a new three-year gas supply agreement with AIX Energy starting around June 2018, at the end of the current contract.

The delivery commitments contained in the supply agreement reflect declining gas production at Kenai Loop but also allow for the possibility of increases in the future.

The agreement requires a firm supply of 1.370 billion cubic feet of gas (about 5 million cubic feet per day) between July 1, 2018, and March 31, 2019; 1.464 billion cubic feet between April 1, 2019, and March 31, 2020 (about 4 million cubic feet per day); and between 1.095 billion cubic feet and 1.825 billion cubic feet (or about 3 million to 5 million feet per day) between April 1, 2020, and March 31, 2021. The contract gives AIX Energy until Sept. 1, 2019, to commit to specific supply deliveries for the third year.

The agreement sets a price of $6.35 per thousand cubic feet in the first year, $6.44 per thousand cubic feet in the second year and $6.54 per thousand cubic feet in the third year.

KL 1-2 and KL 1-4

The future of the offline wells is uncertain.

AIX Energy is considering plans to convert the temporarily suspended KL 1-2 production well into a disposal well. The shut-in KL 1-4 production well is not currently connected to the system, but AIX Energy has expressed an interest in attempting to bring the well online "to provide increased deliverability, to provide redundancy to meet firm gas sales obligations and to possibly increase ultimate recovery," according to the company.

Buccaneer Energy drilled KL 1-4 in October 2013. The well tested at 2.5 million cubic feet per day but later proved to be producing from the same reservoir as KL 1-1.

Earlier this year, AIX hired a geophysical/petrophysical team "to evaluate additional rate enhancing opportunities" at the four

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AIX ENERGY *continued from page 8*

Kenai Loop wells but is still reviewing the results.

Other infrastructure projects

In addition to the four wells, AIX Energy is evaluating other infrastructure projects.

A major unresolved project is a plan to install a gas compression system at the unit. In its plan of development from May 2016, AIX Energy said it expected to install such a system within 12 to 18 months. But after updating internal models based on "flowing and shut-in data," the company recently told officials the system could wait until mid-2018.

The questions to be resolved are the same as last year: whether to purchase a system or to lease it, and whether the system should be gas-fired or electric-fired. The details of the compression system will also guide decisions about trying to revive the KL 1-4 well.

Another focus for AIX Energy has been reducing water-handling costs at the Kenai Loop field. Water handling was the second highest lease operating expense after personnel for the company. An onsite evaporator installed in 2015 provided only "modest benefits," and the company was able to negotiate a 29 percent drop in water handling costs in 2016. ●

Contact Eric Lidji at ericlidji@mac.com

Nicolai Creek future remains uncertain

Aurora Exploration is trying to resolve issues blocking its acquisition of the Nicolai Creek field

By ERIC LIDJI
For Petroleum News

As The Producers was going to print, Aurora Exploration LLC was working through obstacles blocking its acquisition of the Nicolai Creek field from Aurora Gas LLC.

In a confusing twist, Aurora Gas and Aurora Exploration are completely separate companies, despite their similar names and a shared history in the Cook Inlet region.

The deal emerged as part of a bankruptcy case initiated last year.


G. SCOTT PFOFF

Creditors filed an involuntary bankruptcy petition against Aurora Gas in early May 2016, after trouble at two projects left the company unable to meet financial commitments.

The utility Aurora Power Resources Inc. created Aurora Gas as an exploration and production arm in 1999, when major consolidations throughout the oil industry were creating opportunities for smaller companies to pursue overlooked fields in Alaska. The current troubles with the company began after Rieck Oil Inc. acquired Aurora Gas in August 2015 from a joint venture led by Kaiser-Francis Oil Co.-affiliate Aurora-KF LLC.

In early April 2017, Aurora Gas proposed a sale of its assets to pay off creditors. Trading Bay Oil & Gas LLC made an offer in late June 2017 to acquire the entire Aurora Gas portfolio. The offer included a commitment to conduct maintenance work and to use revenue from regular operations to return $2.4 million to Aurora Gas' creditors. The deal fell apart after Cook Inlet Region Inc. and Tyonek Native Corp. rejected the offer. The two companies are landowners at Aurora Gas properties on the west side of Cook Inlet.

The investor Paul Craig owns Trading Bay Oil & Gas. The company is a 50 percent owner of Aurora Exploration, with Aurora Power Resources Inc. owing the remainder.

Escopeta Oil and Gas Corp. and Aurora Exploration made separate offers in late July 2017 to acquire only the Nicolai Creek field, which is on state-owned land.

continued on next page

AURORA EXPLORATION *continued from page 11*

The field was the most productive Aurora Gas property, accounting for about half of its production.

Escopeta offered $125,000 for the Nicolai Creek field and associated seismic information and another $50,000 for related gas supply agreements. Aurora Exploration offered $100,000 in cash for the field, the seismic and the gas supply agreements. The court approved the sale to Aurora Exploration in late August, after Escopeta withdrew its offer. The decision did not include consideration of an associated $10,000 offer from Aurora Exploration to acquire a large commercial contract from Helena Energy LLC.

A bonding issue subsequently delayed the sale.

The Alaska Oil and Gas Conservation Commission ordered Aurora Exploration to either post a $6 million bond to guarantee plugging and abandonment of six Nicolai Creek wells or to commit to plugging and abandoning three wells at the Three Mile Creek field and post a $200,000 bond to guarantee the Nicolai Creek commitments. Aurora Exploration did not agree to buy the Three Mile Creek field from Aurora Gas as part of its offer.

A federal bankruptcy judge overturned the AOGCC decision in late September. Without a resolution to the bonding issue, though, the Alaska Department of Natural Resources is unwilling to approve the lease transfer, which is a requirement for the bankruptcy sale.

The matter remained unresolved as The Producers was going to print, making it difficult to determine what the coming year might hold for development work at Nicolai Creek.

In its last plan of development for the unit, Aurora Gas estimated that Nicolai Creek would become uneconomic in late 2020 or early 2021 without new investment.

The unit was producing from six wells as of August 2016, according to the plan of development. Although the new owner will have discretion over future work, Aurora Gas told state officials that it was considering plans to convert the Nicolai Creek Unit No. 2 and Nicolai Creek Unit No. 9 wells into storage operation with 2.5 billion to 3 billion cubic feet of capacity, was interested in remediating problems at the Nicolai Creek Unit No. 10 and Nicolai Creek Unit No. 11 wells, and believed that a proposed Nicolai Creek Unit No. 12 well could access a potential accumulation in the Nicolai Creek North area.

Without those activities, though, Aurora Gas estimated that the Nicolai Creek unit would become uneconomic within three years and would be abandoned by around mid-2021.

In early September 2017, Aurora Exploration submitted a revised plan of development referring to some long-delayed projects at Nicolai Creek. But the state rejected the plan, saying that the company needed to close on the acquisition before it could propose work.

NAME OF COMPANY: Aurora Exploration LLC
COMPANY HEADQUARTERS: Sugar Land, Texas
TOP EXECUTIVE: G. Scott Pfoff, president
ALASKA OFFICE: 406 West Fireweed Ln., Anchorage, AK 99503
TOP ALASKA EXECUTIVE: David L. Boelens, VP Alaska operations
TELEPHONE: 907-264-6112
COMPANY WEBSITE: www.aurorapower.com

Other fields

The resolution of the bankruptcy case leaves several Aurora Gas fields in uncertainty.

In a recent plan of development for the Three Mile Creek field, Aurora Gas estimated the field would become uneconomic in early 2018 without additional investment activities.

Three Mile Creek is currently producing from just one of its three wells — Three Mile Creek No. 1. The well was producing only 186,000 cubic feet per day as of August 2016, down 10 percent from the year prior, according to company figures included in the plan.

The company suspended production from the Three Mile Creek No. 2 well in 2011, after equipment became lodged in the wellbore during maintenance activities. Attempts to resolve the problem in November 2013 and again September 2014 both failed. Given that plugging the well would require a rig workover, Aurora is considering plans to clean out and test the well prior to officially abandoning it, to make the most of unavoidable costs.

The company drilled the Three Mile Creek No. 3 well in November 2011 but subsequent completion activities were "very disappointing" and the well was never brought into production. The company wants to continue testing the well before approving abandonment plans. In its plan, Aurora said it wants to proceed with the Three Mile Creek No. 2 and No. 3 plans this year, if it could secure a rig. If the work failed to resolve the issues with the two wells, the company would plug all three wells in mid-2018.

Aurora Gas also operates the Lone Creek, Moquawkie and Albert Kaloa fields. ●

Contact Eric Lidji at ericlidji@mac.com

BlueCrest planning one well at Cosmo

Program represents turnaround from threatened suspension, falls short of desired plans

By ERIC LIDJI
For Petroleum News

Earlier this year, BlueCrest Energy Inc. announced plans to temporarily suspend its drilling program at the offshore Cosmopolitan unit while it searched for alternative financing. The temporary suspension, though, could likely end sometime in 2018.

The Texas-based independent announced the suspension after the state withheld between $75 million and $100 million in tax credits for previous work at the offshore Cook Inlet unit. The company told Petroleum News in August 2017 it was relying on the credits to make the project economic and was suspending drilling until it found a replacement.


J. BENJAMIN JOHNSON

In a plan of development for the Cosmopolitan unit, submitted to the Division of Oil and Gas in late September 2017, BlueCrest said it intended to drill at least one well in 2018 and would evaluate its recent drilling activities to determine its activities going forward.

Rig financing

After several years as a partner at Cosmopolitan, and later as an operator in exploration and appraisal activities, BlueCrest brought the unit into production from an existing well in early 2016 and began development drilling with a custom rig in November 2016.

The BlueCrest Rig No. 1 was designed to accommodate directional wells and laterals drilled to an offshore target from an onshore drilling pad in the Anchor Point region. The rig has a 750-ton top drive and a 7,500-pounds-per-square-inch drilling mud system, making it capable of drilling 24,000-foot wells at a

NAME OF COMPANY: BlueCrest Energy Inc.
COMPANY HEADQUARTERS: 1320 South University Dr., Ste. 825, Fort Worth TX, 76107
TOP EXECUTIVE: J. Benjamin Johnson, director, president, and CEO
TELEPHONE: 817-731-0066
COMPANY WEBSITE: www.bluecrestenergy.com

vertical depth of some 7,000 feet.

In April 2015, the Alaska Industrial Development and Export Authority agreed to loan BlueCrest as much as $30 million toward the $40 million cost of the drilling rig. In addition to seeking AIDEA funding, BlueCrest expected to use state tax credit payments to fund a $15 million reserve account to cover any unexpected shortfalls in financing.

BlueCrest asked AIDEA in late 2016 to revise the terms of the loan. According to the company, work on the drilling rig took longer than expected, which shifted the timeline for drilling to begin and for the company to earn revenue from production. Additionally, according to the company, the deferment of the tax credit payments from the state complicated efforts to fund the $15 million reserve account. AIDEA agreed to extend some of the deadlines in the loan package as well as the terms of the reserve account.

2017 program

BlueCrest initially planned to conduct a five-well program starting in early 2017: the H-16 well, the H-14 well and H-14L lateral, and the H-12 well and H-12L lateral. The company ultimately completed two wells and three sidetracks at Cosmopolitan this year.

The company began drilling the Hansen 16, or H-16, well in November 2016 and completed the well in March 2017. The 22,810-foot well reached a vertical depth of 7,089 feet, according to the Alaska Oil and Gas Conservation Commission. The company described the well as the longest extended reach well ever drilled in the Cook Inlet.

As of late September 2017, after a fracturing operation, the H-16 well was producing 330 barrels of oil per day from the Hemlock formation, according to the company. The compartmentalized nature of the reservoir requires fracturing operations after drilling activities have been completed to open up impervious barriers in the reservoir rocks.

The fractures at the Cosmopolitan unit are larger than previous Cook Inlet fracturing efforts and closer to developed areas than most Alaska operations. Those two factors turned the project into a symbol of the industrial process in hearings before the Alaska Oil and Gas Conservation Commission about hydraulic fracturing regulation in Alaska.

In mid-March 2017, BlueCrest began drilling the H-14 well and the associated H-14L lateral. A technical problem on the lateral complicated operations at the project.

"BlueCrest was running the liner into the H14 Lower Lateral when the Baker Hughes Packer/Liner Hanger Assembly failed and prematurely & permanently set the liner in the well (-4,000 ft. short of TD (total depth))," the company wrote in its plan. "BlueCrest completed a milling/fishing job to recover the liner that was left in the cased hole."

BlueCrest started three separate sidetrack operations on the H-14 Lower Lateral before completing the well at 22,300 feet on Sept. 25, 2017, according to the company. As of the date of the report, two days later, the company was preparing to run the liner on the well.

The Cosmopolitan unit produced 49,653 barrels of oil in 2016 from a previously drilled well and produced 28,136 barrels of oil during the first half of 2017, according to the AOGCC. Cumulative oil production through June 2017 was 111,293 barrels. The cumulative total includes a previous pilot project by Pioneer Natural Resources Inc.

2018 plans

In announcing plans to suspend drilling at Cosmopolitan, BlueCrest President and CEO Benjamin Johnson said, "We're going to finish drilling what we're doing right now. It's not an immediate shutdown." The statement suggested that the company would finish work on the H-14 well and H-14L lateral but defer the H-12 well and H-12L lateral.

In its plan of development, BlueCrest said it would drill at least one well at Cosmopolitan in 2018 and listed the H-16 Upper Lateral as the most likely candidate at the moment.

The company said that it had already received a permit from the Alaska Oil and Gas Conservation Commission to drill the H-12 development well but needed to revise the permit to accommodate changes to its completion package. As of late September 2017, the AOGCC had yet to include the H-12 drilling permit on its weekly well report.

In June, the AOGCC issued a spacing exemption, allowing BlueCrest to drill the H-12 well within the same governmental section as the H-14 and H-16 wells and their laterals.

BlueCrest intends to request an AOGCC drilling permit for the H-16 Upper Lateral and H16 Exploratory Lateral either later this year or early next year, according to the plan.

As currently envisioned, the H-16 Upper Lateral would target the Starichkof. Pennzoil discovered Cosmopolitan in 1967 with the Starichkof State No. 1 well. Phillips confirmed the discovery and also discovered Hemlock oil with the Hansen No. 1 well in 2001.

The state Division of Oil and Gas recently approved the formation of a participating area at the Cosmopolitan unit that includes both the Starichkof sands and the Hemlock.

Future plans

Even if drilling activities proceed this year as currently planned, they would be a reduction of the pace of activity BlueCrest might prefer under ideal economic conditions.

The company intended the five-well program to be the first stage in a full development program that would potentially require 20 wells over a seven-year timeline. The facilities at the Cosmopolitan unit are capable of handling as much as 10,000 barrels per day.

"This project has a tremendous amount of value. It offers the opportunity for years and years of good, viable drilling to develop the hundreds of millions of barrels of oil in the ground," Johnson told Petroleum News in early August 2017. "But we relied on the state's commitment that they were going to participate in the funding in the project."

The Cosmopolitan development project is occurring on a 38-acre parcel, which is much larger than the existing pad and facility and could easily accommodate expansion.

Earlier this year, BlueCrest contracted lease ADL 391902 from the unit, which was one of the three leases offered in a special sale in June 2011 because of their prospectivity.

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NSB Service Area 10 Utilities

Water Treatment Facility, Wastewater Facility, Oxbow Landfill

The North Slope Borough (NSB) has recently designed and built a state-of-the-art utility plant and has also invested to expand the Oxbow Landfill. These investments will ensure the NSB can safely and reliably provide services to industries within the Service Area 10. ICE Services has been contracted by the NSB to manage and operate both utilities. ICE Services provides ADEC certified operators to operate these utilities.

The Water Treatment Facility can produce up to 420,000 gallons/day of quality drinking water that meets all State and Federal regulations, using high tech Membrane Filtration along with UV disinfection to ensure protection of public health.

The Wastewater Facility receives domestic wastewater from industrial facilities and work camps on the road system of Service Area 10. The Wastewater Treatment Facility can treat up to 420,000 gallons/day of wastewater to meet all State and Federal regulations, using modern Sequence Batch Reactors along with chlorination to ensure the discharge will not harm the environment.

The Hot Water Facility has the capability to heat raw water on-demand as required safely and efficiently. In addition, chemicals and /or additives can be mixed with hot water to produce the fluid composition needed for industrial applications in a condensed timeframe resulting in cost-savings to customers.

The Oxbow Landfill is the only Class 1 Industrial Landfill on the North Slope. The recent expansion of this critical asset will allow continued use for up to an additional 50 years.

CONTACT

SA10 Industrial Development
(907) 852-0252
www.north-slope.org/departments/administration-finance/sa10-industrial-development

ICE Services
(907) 670-2258
www.iceservices.net/utility

BLUECREST *continued from page 15*

History

Pennzoil discovered the Cosmopolitan oil field off of Anchor Point in 1967 with the Starichkof State No. 1 discovery well and the down-dip Starichkof State Unit No. 1 well.

ARCO Alaska acquired the prospect in the 1990s, and Phillips Inc. inherited the leases after it acquired ARCO's producing assets in Alaska in early 2000. By the turn of the century, improvements in drilling technologies allowed Phillips to target the offshore prospect from an onshore pad, some 2.5 miles away, using directional wells. The company drilled the Hansen No. 1 well in 2001, confirming the presence of oil in the Starichkof sands and discovering productive sands in the deeper Hemlock formation.

In 2003, after a merger, ConocoPhillips Alaska Inc. drilled the Hansen No. 1A sidetrack of the original well to target the Starichkof and the Hemlock reservoirs. A subsequent flow test produced 1,000 barrels of oil per day and 14,851 cumulative barrels.

ConocoPhillips partnered with Pioneer Natural Resources in 2005 on a joint 3-D seismic program. After the companies dissolved their partnership, Pioneer acquired ConocoPhillips' interest and became operator of the field. Even though Pioneer was nervous about being so far from existing infrastructure, the promise of a resource estimated in the range of 30 million to 100 million barrels convinced the company to drill Hansen No. 1A-L1, a "long-reach undulating lateral" off of the sidetrack, in 2007.

Pioneer fracture stimulated an interval at Hansen No. 1A-L1 in 2010. Under a pilot trucking project, the company produced more than 33,000 barrels from the field.

BLUECREST ENERGY

After several years as a partner at Cosmopolitan, and later as an operator in exploration and appraisal activities, BlueCrest brought the unit into production from an existing well in early 2016 and began development drilling with a custom rig in November 2016.

Pioneer soured on the project in early 2011. The company terminated the unit and relinquished all its leases except the two that were held by wells, which it sold to BlueCrest and its operating partner Buccaneer Energy Ltd. Apache Alaska Corp. bought the remaining leases but later sold them to the Buccaneer and BlueCrest partnership.

After drilling the Cosmopolitan No. 1 well, Buccaneer announced previously unknown oil-bearing intervals, and some gas production, too, but postponed a "more extensive flow test." Before it could drill a follow-up well, Buccaneer sold its minority stake in the Cosmopolitan prospect to BlueCrest in an attempt to improve its financial situation by selling off some of its varied Alaska assets. Soon after, Buccaneer filed for bankruptcy. ●

Contact Eric Lidji at ericlidji@mac.com

BP wants stable production amid cuts

Oil production at Prudhoe Bay has yet to fall as sharply as a steep decline in recent drilling activity

By ERIC LIDJI
For Petroleum News

BP Exploration (Alaska) Inc. responded to the current economic climate with a drastic reduction in drilling activity at the Prudhoe Bay unit, the only unit it operates in Alaska.

The local subsidiary of the global energy company drilled 75 development wells at the North Slope unit in 2015, 43 wells in 2016 and only 11 through the first half of this year.

And yet, production has remained stable, suggesting new operational efficiencies.


JUDY PATRICK
JANET WEISS

BP files three plans of development each year for the Prudhoe Bay unit — one for the Initial Participating Areas early in the year, one for the Greater Point McIntyre Area in the middle of the year and one for the Western Satellites toward the end of the year.

Initial Participating Areas

In its most recent plan of development for the Initial Participating Areas, from March 2017, BP announced a 13.5 percent decline in drilling activity for the current year.

The company said it planned to drill between four to seven rotary sidetracks and 20 to 24 coiled tubing drilling sidetracks in the current development year, down from seven rotary sidetracks and 28 coiled tubing sidetracks in 2016. The plan also included one new well at the Initial Participating Areas in 2017, down from two new wells in 2016. The company expected its rigged workover program to remain flat, at two to four projects.

The proposed 2017 program is geographically focused — three sidetracks at F pad, four sidetracks at 3 pad, 9 pad and 17 pad and a sidetrack at J pad, plus a few scattered wells.

Actual IPA drilling activity through the first half of the year included two sidetracks at 3 pad, one at 9 pad, one at 15 pad and sidetracks at D pad, F pad, L pad and V pad.

Even with the decline in drilling activity, BP provided a production forecast in line with 2016 levels — between 158,000 and 198,000 barrels per day for oil and between 30,000 and 41,000 bpd for natural gas liquids. By comparison, the company projected oil production between 157,000 and 196,000 bpd and natural gas liquids production between 36,000 and 45,000 bpd in a revised 2016 forecast.

Actual crude oil and condensate pro-

continued on next page

BP *continued from page 19*

duction from the Initial Participating Areas was 197,900 bpd from the in 2016, up from 196,400 bpd in 2015, and actual natural gas liquids production was 38,000 bpd in 2016, equal to 2015.

The company attributed the increased Initial Participating Areas oil production in 2016 to "the lack of any production impacting facility TARs (turnarounds), strong wellwork and drilling performance, and increased emphasis on mitigating and minimizing deferrals."

The Initial Participating Areas production increases in 2016 came despite a 38 percent decline in drilling and a nearly 19 percent decline in rate-adding well work projects.

BP originally proposed a 31-well program for the Initial Participating Areas in 2016 and actually drilled 37 wells, down from a 60-well development program in 2015. The company performed approximately 1,000 well work jobs at the Initial Participating Areas in 2016, including 336 that added production. The company performed approximately 1,800 jobs at the Initial Participating Areas in 2015, of which 413 were rate adding.

Combining drilling and workover operations, the company performed 3.8 rig years of work in 2015, 1.8 rig years of work in 2016 and proposed 1.3 rig years of work for 2017.

Greater Point McIntyre Area

The future of the Greater Point McIntyre Area depends on seismic.

BP conducted the North Prudhoe seismic survey over the northern portion of the Prudhoe Bay unit in 2014 and 2015, completed the survey in April 2015 and completed a stage of the processing in September 2016, according to its most recent plan of development.

NAME OF COMPANY:
BP Exploration (Alaska)
COMPANY HEADQUARTERS: BP, London
ALASKA OFFICE: 900 Benson Blvd.,
Anchorage, AK 99508
TELEPHONE: 907-561-5111
TOP ALASKA EXECUTIVE: Janet Weiss, BP Alaska regional president
COMPANY WEBSITE: www.bp.com

After a year of strong production growth in 2016, the five fields that make up the Western Satellites at the Prudhoe Bay unit all experienced declines this past year.

Results will likely guide future development decision. "Interpretation of the data is currently being prioritized across the Prudhoe Bay Unit. Interpretation will focus on improving the structure mapping over the field and an understanding of the subsurface areas of interest (Kuparuk, Sag, Ivishak, Lisburne, and Alapah intervals)," BP wrote.

Liquids production increased at the Lisburne, Niakuk and Raven fields, declined at the Point McIntyre field and was offline at the North Prudhoe Bay and West Beach fields.

The only drilling activities planned for the Greater Point McIntyre Area this year are one development well at the Lisburne field and one development well at the Raven field.

BP drilled the L3-25 well at the Lisburne field this year and said it was considering several potential well locations for the future. The company completed two wells — L1-13 and L5-12A — and performed 18 rate-adding workover projects at 17 existing wells in 2016. The company also made its Lisburne Gas Cap Water Injection Project permanent in late January 2017, after the AOGCC approved the continuation of the pilot project.

BP plans to drill the NK-15A injection well at the Raven field to target the South Fault Block at the field, at which point the existing NK-65A well would be converted to a producer from the Sag River formation "to recover remaining resource in that area."

The company drilled the NK-38B sidetrack of the existing NK-38A sidetrack into an unswept portion of the Ivishak reservoir at Raven in 2016 and returned the NK-65A well to injection. The company drilled the NK-14B development well in March 2017, during the previous development year, to delineate the outer boundaries of the Raven oil pool.

BP made no firm drilling commitments at the Niakuk field for the current year, although the company said potential drilling targets are "continually being evaluated." The company performed non-rig workover projects on the NK-42 and NK-09 wells in 2016.

BP also made no firm drilling commitments at the Point McIntyre field for the current year, but it expects improved production and operations from the largest field in the area after restoring the suspended Point McIntyre pipeline into Gathering Center 1 last year.

BP said that the results of the North Prudhoe seismic survey, and other technical assessments, could improve ongoing studies at North Prudhoe Bay and West Beach.

JUDY PATRICK

Western Satellites

After a year of strong production growth in 2016, the five fields that make up the Western Satellites at the Prudhoe Bay unit all experienced declines this past year.

Aurora produced 4,696 barrels of oil per day in the year ending June 2017, down from 6,303 bpd the year before and up from 4,305 bpd during the 2014-15 reporting year.

BP brought the S-113BL1 well online in the second half of 2016 and performed a workover at the S-109 well in the first quarter of this year. The company also performed 42 workover operations at Aurora during the reporting year — only four added production.

Borealis produced 6,040 barrels of oil per day in the year end-

continued on next page

BP *continued from page 21*

ing June 2017, down from 8,517 bpd the year before and down from 8,768 bpd during the 2014-15 reporting year.

The company shut-in V pad production at the field in June 2016 in response to concerns over subsidence and potential piping stress. The company completed repairs on the facilities in late 2016 and returned all wells to production in the first quarter of this year.

The V pad repairs also impacted operations at the Orion field.

BP performed 61 workover operations at Borealis during the year — 12 added production.

"The Borealis owners will continue to evaluate the optimal number of development wells and their locations throughout the life of the reservoir," the company wrote in its plan.

Midnight Sun produced 983 barrels of oil per day in the year ending June 2017, down from 1,134 bpd in the year prior and up from 964 bpd in the 2014-15 reporting year.

BP brought the P1-122i injection well into operation in October 2016, after a round of repairs. The company performed rate-adding activities on the E-101 and E-102 wells.

The plan includes no detailed program for drilling or workover activities for the reporting year ending June 2018. "As the waterflood continues to mature, sidetracking the producers within the pool to maximize oil recovery will be evaluated after the benefits from WAG (water alternating gas) injection are realized," the company wrote in its plan.

Orion produced 3,469 barrels of oil per day in the year ending June 2017, down from 4,747 bpd in the year prior and 4,693 bpd during the 2014-15 reporting year.

The company shut-in V pad production at the field in June 2016 in response to concerns over subsidence and potential piping stress. The company completed repairs on the facilities in late 2016 and returned all wells to production in the first quarter of this year.

BP performed 55 workover operations at Orion during the year — nine added production.

The wells in the northwest corner of the Orion participating area have experienced high rates of downtime in recent years, in part because of sand production down hole.

The company is currently evaluating potential sidetracks at two shut-in wells — L-200 and L-205. The sidetrack designs could be useful for other wells in the troublesome region.

BP recently "initiated a study to refresh the design and potential costs of an I Pad development," which has been in the works at the Orion field for more than a decade.

Polaris produced 3,891 barrels of oil per day in the year ending June 2017, down from 4,306 bpd in the year prior and up from 3,890 bpd in the 2014-15 reporting year.

BP performed 11 workover projects at Polaris over the year — two added production.

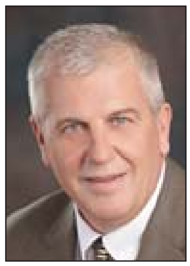
A potential viscous oil development at M pad and S pad at Polaris remains under consideration and depends on economics and the results of sand control technology trials. ●

Contact Eric Lidji at ericlidji@mac.com

BRPC working on 2019 Mustang start-up

Company is working to certify existing well by late 2017 to address production deadline imposed by state

By ERIC LIDJI
For Petroleum News


BART ARMFIELD

NAME OF COMPANY:
Brooks Range Petroleum Corp.
COMPANY HEADQUARTERS:
510 L St., Ste. 601, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: Bart Armfield, CEO, president
TELEPHONE: 907-339-9965
COMPANY WEBSITE: www.brooksrangepetro.com

In its most recent plan of development for the Southern Miluveach unit, Brooks Range Petroleum Corp. said it expected to bring the Mustang field into production in early 2019.

The proposed target is more than a year beyond a December 2017 deadline imposed by the state Division of Oil and Gas, under the terms of an extension granted in early 2016.

The Division of Oil and Gas had yet to approve or reject the plan of development, and so the question of timing remained unresolved, as The Producers was going to print.

But a potential solution appeared to be in the works. Earlier in the year, Brooks Range Petroleum announced it was working to certify one of its existing wells at the unit as capable of producing in paying quantities, which would protect the unit from termination.

In its current plan, submitted in early October 2017, Brooks Range Petroleum said it was currently re-entering the North Tarn No. 1A sidetrack for fracture stimulation and testing.

To date, Brooks Range Petroleum has built the Mustang pad and the Mustang road connecting the pad to Drill Site 2M at the

Kuparuk River unit. The remaining pieces of the development include drill site facilities, a 15,000-barrel-per-day central processing facility, two cross-country pipelines, associated infrastructure such as communication and housing facilities, and as many as 26 wells — nine for production and 17 for injection.

Under the program described in its plan of development, Brooks Range Petroleum would install on-pad piles in the first quarter of 2018 and install cross-country pipelines in late 2018 and early 2019. The company would also finish building the remaining modules next year, bringing the Alaska-built modules to Mustang between June and December 2018 and the Canadian-built modules to the field by sealift in August 2018. A 60-to-90-day system-wide review in late 2018 would precede project start-up in early 2019.

The state approved a previous plan of development for the unit despite concerns about the December 2017 deadline. "The Division would like to see BRPC succeed with SMU," then-Acting Division of Oil and Gas Director James B. Beckham wrote. "But the tight schedule, impending unit expiration, and concerns BRPC has raised with technical issues and financing cause the Division to question the likelihood of success." Even with those concerns, he approved the plan because it "set forth a possible path toward production."

Brooks Range Petroleum operates the Mustang project on behalf of CaraCol Petroleum LLC, TP North Slope Development LLC, MEP Alaska LLC, Nabors Drilling Technologies USA Inc., AVCG LLC, Mustang Road LLC and MOC1 LLC. Mustang Road and MOC1 are subsidiaries of the Alaska Industrial Development and Export Authority, which helped finance the road, pad and processing facilities projects.

Additional financing

In an April 2017 annual report, officials from Alpha Energy Holdings Ltd. — an affiliate of one of the working interest owners — wrote that the joint venture was responding to the current economic climate by delaying drilling until after the field came into production.

The idea was to finance development drilling using cash flow from oil production rather than additional financing. The report also noted that construction of the Mustang Operations Center must resume before any additional drilling activities could continue.

In late June 2017, the Alaska Industrial Development and Export Authority approved an additional $2.5 million investment into the Mustang projection as bridge financing. The public corporation previously invested $20 million toward the gravel Mustang Road and associated pad and $50 million toward the forthcoming Mustang Operations Center.

AIDEA also announced that Brooks Range Petroleum was working with the Walker administration and a team of contractors on a plan to gain certification for an existing Mustang well by the third quarter of this year and bring the unit online in late 2018.

"The June 29 resolution that was approved by the AIDEA board is a positive step forward in getting the Mustang project back on track," Brooks Range Petroleum Chief Operating Officer Bart Armfield told Petroleum News by email at the time. "BRPC is planning to conduct some field work on the project in the coming months with an ultimate objective to engage with other third party entities to fully fund the overall project, with an anticipation of first oil production from the facility in late Q4 2018."

Expansion

To improve regional economics and save valuable acreage in the vicinity, Brooks Range Petroleum requested a major expansion of the Southern Miluveach unit in late June 2017.

The proposed expansion would add approximately 19,552 acres from 11 leases to the north, west and northeast of the unit, more than doubling its size. According to the company, the expansion acreage is only marginally economic on its own. Developing those leases as satellites of the Mustang project would improve their economic profile.

In a supplemental plan of development, Brooks Range Petroleum proposed building the 15-acre gravel Pinto pad on ADL 391549 to support a 40-well development program. Any production from the expansion acreage would be processed at the Mustang facilities.

According to a timeline provided by the company, Brooks Range Petroleum would spend the next year evaluating the Torok and the Kuparuk formations in the expansion acreage by interpreting seismic data and monitoring nearby wells. An exploration program to test the Torok formation would begin as early as the 2018-19 winter drilling season, either testing an existing well or drilling and testing a new well in the expansion area. If warranted, the company would also evaluate the Kuparuk formation in the acreage.

If the company sanctioned a development, road and pad construction would likely begin in early 2020 with development drilling in early 2022 and first oil by the end of that year.

The proposed expansion would essentially bring the unit to the original boundaries proposed by Brooks Range Petroleum when it first requested the unit in late 2010. ●

Contact Eric Lidji at ericlidji@mac.com

Caelus maintains Oooguruk suspension

Activities this year include workover projects and planning for future drilling activities; Nuna also on hold

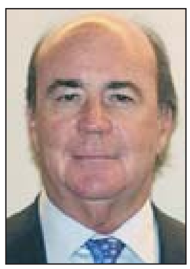
By ERIC LIDJI
For Petroleum News

NAME OF COMPANY: Caelus Energy
COMPANY HEADQUARTERS: Dallas, Texas
TOP EXECUTIVE: James C. Musselman, president and CEO
TELEPHONE: 214-368-6050
WEBSITE: www.caelusenergy.com

After suspending development drilling at its Oooguruk unit in May 2016, Caelus Energy Alaska LLC expressed its long-term confidence in the North Slope unit by saying it would begin drilling again "when oil prices recover and investor confidence resumes."

Apparently, neither condition has yet occurred.

The local subsidiary of Texas-based Caelus Energy LLC planned no drilling activities at Oooguruk over the coming year, running from September 2017 to September 2018.


JAMES MUSSELMAN

The forecast might be improving, though.

The company told state officials it intended to conduct a workover campaign over the current development year and had identified six new wells to pursue in the future.

Even so, the company also suggested that plans to bring the Nuna satellite into production by late 2018 could be further delayed by oil prices and by oil tax policy.

The Oooguruk unit is developed from three pools: Nuiqsut, Kuparuk and Torok.

To date, Caelus and its predecessor Pioneer Natural Resources Alaska Inc. have drilled 43 wells at the unit — 28 at the Oooguruk Nuiqsut participating area, five at the Oooguruk Kuparuk participating area and four at the Oooguruk Torok participating area, plus one disposal well, and five appraisal and exploration wells outside of the participating areas.

The Oooguruk unit produced 4.1 million barrels in 2014, 4.2 million barrels in 2015, 5.2 million barrels in 2016 and 2.4 million barrels through the first half of this year, according to the Alaska Oil and Gas Conservation Commission. Cumulative oil production from the Oooguruk unit was 30.78 million barrels by the end of June 2017.

Recent activities

Without drilling activities, development work in the year ending in August 2017 focused on maintaining and upgrading facilities and on addressing development in other ways.

At the Oooguruk Nuiqsut participating area, Caelus evaluated three existing injection wells in a proposed expansion area at the unit — the ODSN-06i well in the northeast corner of the participating area near the Ivik exploration well; the ODSN-07i well in the northern end of the participating area drilled to support the ODSN-02 and ODSN-28 production wells; and the ODSN-10i well in the southwest corner of the expansion area.

The company briefly used ODSN-07i as a production well before converting it to an injection well in January. The company is also running extended pre-production tests from the ODSN-06i and ODSN-10i wells "to assess long term reservoir performance in these new development areas" before eventually converting the wells to injection.

And the company is monitoring the ODSN-03i after discovering early water injection breakthrough in its offset producing wells, ODSN-02 and ODSN-04. The company plugged a lateral in the well in July 2016 to isolate the relevant zone and removed the plug in April to resume injections and monitoring. "The surveillance data from the program will be used to assess reservoir management and remediation alternatives."

The injection rate of the ODSN-27i and ODSN-34i wells was "significantly lower" following the shutdown of seawater deliveries from the Kuparuk River unit in September 2016. "Attempts were made to clear any debris possibly plugging the lateral by back-flowing and surging the wells. Injection performance is under review," Caelus wrote.

At the Oooguruk Kuparuk participating area, oil production continued from horizontal producers ODSK-14 and ODSK-41, with ODSK-38i as the primary injector. The company returned the ODSK-35Ai well to injection this year. The company shut-in the ODSK-33 well "due to very high water-cut and significant hydraulic back-out effects."

At the Oooguruk Torok participating area, production continued from the ODST-39 and ODST-45A wells. The company recompleted the ODST-45A well in April 2016 to remove scale build up. The effectiveness of an April 2017 workover to address the problem is still being evaluated. The company also restored injection at the ODST-46i well after repairing a tubing leak to the inner annulus caused by a leaking gas lift valve.

The ODST-47 well is non-productive "due to mechanical failures." Caelus is planning to contract the participating area to remove acreage associated with the well and instead use the well slot for future development of the larger Oooguruk Nuiqsut participating area.

Upcoming work

The work Caelus has announced for the Oooguruk unit for the 2017-2018 development year is focused on the Oooguruk Nuiqsut participating area, the largest of the pools.

The company has finished planning activities for six of the remaining 13 well locations — eight new wells and five reclaimed wells — intended for the participating area. The new wells will be ODSN-05, ODSN-08, ODSN-09, ODSN-11, ODSN-12 and ODSN-20.

Caelus is also planning eight workover projects at the unit, scheduled to start in August 2017. The workovers include recompletions to improve flow efficiency at seven existing wells (ODSN-02, ODSN-04, ODSN-16, ODSN-17, ODSN-28, ODSN-31 and ODSN-39) and a test of the Kuparuk formation in the Ivik fault block using a dual Nuiqsut and Kuparuk completion in the existing ODSN-29 well. The company is also planning to perform integrity repairs on three existing wells, ODSN-02, ODSN-04 and ODSN-28.

Slowdown at Nuna

The future of the Nuna development is less certain than existing Oooguruk developments.

Caelus fully sanctioned the Nuna development in early 2015 and subsequently completed some initial infrastructure projects, including the Nuna Drill Site 1 and access road. The company also began permitting a second pad, should it decide to expand the project.

With the suspension of drilling activities in early 2016, Caelus also postponed aspects of Nuna, moving the startup date to "2018 or later" from an earlier date of late 2017.

In the 2016-2017 year, Caelus performed non-drilling tasks at Nuna. The company continued refining its cost estimates and assessing the overall commercial viability of the project based on drilling and engineering results and on permitting requirements. Over the coming year, the company expects to continue design, engineering and procurement activities and continue ongoing geologic studies with the goal of a "2018 or later" startup. Those plans also include an ongoing evaluation of "facility construction schedule and cost in light of oil price and tax structure environment," according to the company.

In early 2017, during testimony for the oil tax revisions in House Bill 111, Senior Vice President of Alaska Operations Pat Foley said that the bill would erode the value of the Nuna development and would require higher oil prices for the project to proceed.

Even under normal circumstances, Caelus was skeptical about the economics of the project and requested royalty relief from the state. The Alaska Department of Natural Resources approved the relief in January 2015, lowering the royalty rate on Torok oil production from five leases to 5 percent until the development earns $1.25 billion.

The royalty relief decision involved a series of work commitments, including one requiring Caelus to begin sustained oil production from the Torok by Sept. 30, 2017.

When it became clear that the deadline would be impossible to reach, Caelus requested a two-year extension of its final work commitments. The state rejected the request, saying it did not have the authority to grant an extension but would welcome a new application.

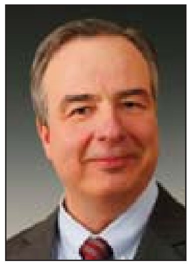
Caelus Energy Alaska spokesman Casey Sullivan told Petroleum News that the company would "most certainly" reapply for royalty modification at some point in the future. ●

Contact Eric Lidji at ericlidji@mac.com

ConocoPhillips advancing several projects

Company is actively developing Kuparuk River unit, Colville River unit and Greater Mooses Tooth unit

By ERIC LIDJI
For Petroleum News



JOE MARUSHACK

NAME OF COMPANY: ConocoPhillips Co.
COMPANY HEADQUARTERS: Houston, Texas
ALASKA OFFICE: 700 G St., Ste. 1950, Anchorage, AK 99501
TOP ALASKA EXECUTIVE: Joe Marushack
PHONE: 907-276-1215
COMPANY WEBSITE: www.conocophillipsalaska.com

ConocoPhillips Alaska Inc. is the most active operator on the North Slope and one of the few companies sanctioning new North Slope developments despite the economic climate.

The local subsidiary of the largest independent exploration and production company in the world was not totally immune to larger economic forces over the past year. The company scaled back its development plans and marketed its Cook Inlet properties. But the company started production at Drill Site 2S and the CD-5 pads in recent years, is currently working to bring the 1H NEWS and the GMT-1 pads into production over the next year and is advancing a range of other developments through preliminary stages.

The company currently operates four North Slope units: the Kuparuk River unit, the Colville River unit, the Greater Mooses Tooth unit and the Bear Tooth unit.

The Kuparuk oil field

ConocoPhillips is currently pursuing two parallel strategies at the Kuparuk River unit.

The first is a targeted infill program to improve production at existing pads. The program generally includes a small number of new wells and a larger number of sidetracks.

The second is a gradual expansion of facilities targeting undeveloped sections of the unit.

ConocoPhillips produced 110,700 barrels per day at the unit in 2013, 110,200 bpd in 2014, 104,600 bpd in 2015 and 103,000 bps in 2016, according to the company. At the main field, ConocoPhillips produced 85,700 bpd in 2013, 83,200 bpd in 2014, 78,200 bpd in 2015 and 78,100 bpd in 2016. At the satellites, the company produced 25,000 bpd in 2013, 27,000 bpd in 2014, 26,400 bpd in 2015 and 24,900 bpd in 2016.

In its most recent plan of development for the unit, ConocoPhillips proposed a reduction in infill activities at the main Kuparuk oil field. For the year ending July 2018, the company plans to drill four new rotary wells and 16 coiled tubing drilling sidetracks, down from eight new rotary wells and 20 coiled tubing drilling sidetracks the year before.

The eight new wells were all at the Drill Site 2S development, in the southwest of the unit. The completion of initial development is one reason behind the expected decline.

The 20 sidetracks were drilled throughout the unit. The program included a cluster of five sidetracks at Drill Site 1H, Drill Site 1G and Drill Site 1B at the eastern edge of the unit; a cluster of four sidetracks at Drill Site 1L at the south of the unit; a cluster of three sidetracks at Drill Site 2M and Drill Site 2K near the 2S development; a cluster of four sidetracks in the north of the unit at Drill Site 3O, Drill Site 3Q, Drill Site 3N and Drill Site 3H; and sidetracks at Drill Site 3G, Drill Site 3F, Drill Site 2X and

Drill Site 2B.

ConocoPhillips credited its sidetrack program — 55 laterals at the 20 sidetracks — with adding some 3,500 bpd in incremental oil production. The company credited a rig workover campaign with adding 1,600 bpd at the Kuparuk participating area and a non-rig workover program with adding an additional 10,700 bpd.

The company has been selecting sidetrack candidates using two 3-D seismic surveys — the Kuparuk West Sak survey from 2005 and the Western Kuparuk survey from 2011.

The construction of new facilities is part of a wider "infrastructure-led exploration" strategy, where the company pursues developments near existing wells or available infrastructure. The strategy was directly responsible for the Drill Site 2S project.

Although the company is considering projects that would require new drill sites, it has no plans to develop any new sites targeting the Kuparuk A and C sands before July 2018.

One potential project is a development in the Moraine interval at the western edge of the unit. The company has drilled three recent wells into the Moraine at the Kuparuk River unit, including a pilot project from the paired 3S-620 producer and 3S-613 injector wells.

"Results from special core analyses and reservoir performance from the 3S-620 producer well and 3S-613 injector well will guide future development plans for the Moraine interval," the company recently told state officials but offered no firm development plans.

Kuparuk satellites

ConocoPhillips made no firm drilling commitments at the four Kuparuk River unit satellites — West Sak, Tarn, Meltwater and Tabasco — for the coming year, aside from the resumption of drilling activities at the previously announced 1H NEWS development.

West Sak is the largest of the satellites.

ConocoPhillips did not drill any development wells at West Sak in 2016, focusing instead on "surveillance and optimization of existing wells," according to the most recent plan of development. For the current year, the company said it was planning to "focus on existing developments" while also studying a range of potential future developments at the field.

The largest project is the planned resumption of activities at the 19-well Drill Site 1H NEWS development. The company placed the project on hold last year after completing major infrastructure construction but has said the project is on track for start-up by year-end. The company began drilling activities at the viscous oil project in August 2017.

The development of the CD-5 pad has opened up several decades' worth of development activity on properties farther to the west, including the GMT-1, GMT-2 and Willow prospects at the Greater Mooses Tooth unit and prospects at the Bear Tooth unit.

ConocoPhillips is also studying potential West Sak developments at the existing Drill Sites 1D, 1C, 3K and 3N. The 1C program could include three new development wells at "lower-value" targets. The 3K and 3N programs will most likely be developed in phases.

The company is using recent drilling activities in the region to study a "potential major multi-well" Eastern NEWS development, which would require a new drill site.

The company is also considering potential Drill Site 3R development, which could require an expansion of the existing Drill Site 3R. Earlier this year, the company drilled and completed a pair of pilot wells — the 3R-101 producer and 3R-102 injector — at Drill Site 3R. The company is evaluating the project using a recently completed 3-D seismic survey over 47 square miles in the northern end of the unit. The company acquired and licensed the survey in mid-2014 and processed a portion of the survey during 2016.

ConocoPhillips did not drill any wells at the Tarn, Meltwater

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CONOCOPHILLIPS *continued from page 29*

and Tabasco satellites in 2016 and was not planning any development drilling at the three fields for this year.

The Alpine field

The Colville River unit is an increasingly important center of regional activity for ConocoPhillips, allowing the company to expand development in at least two directions.

In its most recent plan of development, the company proposed a 14-well development program at the unit for the coming year. The proposed program is part of the initial campaign at the CD-5 pad, which came online in late 2015. The company drilled nine development wells — three producers and six injector s— from the CD-5 pad in 2016.

The program for the current year includes both rotary and coiled tubing drilling wells.

The rotary program calls for drilling seven multilateral wells — three producers and four injectors — into the Alpine participating area, all from the new CD-5 pad. The wells are CD5-20, CD5-17, CD5-19, CD5-9A, CD5-9C, CD5-10AB and CD5-10BC. The company already completed the CD5-18 multilateral well at the unit in January 2017.

The company is also planning four other Alpine participating area wells: three multilateral wells from CD-5 and a re-drill of an existing well at the CD-4 pad. All four wells are currently scheduled for subsequent years, but could be moved to this year.

The coiled tubing drilling program involves adding one or more laterals to the existing CD2-39 and CD2-47 wells. Depending on the results, the company might pursue similar opportunities at the CD2-42, CD2-33B and CD1-03A wells, and other confidential wells.

The recently drilled CD5-18 multilateral well, the seven planned rotary wells, the four un-named wells at CD-5 and CD-4 and the two coiled tubing drilling wells total 14 wells.

Colville River unit expansions

The development of the CD-5 pad has opened up several decades' worth of development activity on properties farther to the west, including the GMT-1, GMT-2 and Willow prospects at the Greater Mooses Tooth unit and prospects at the Bear Tooth unit.

Over the past year, ConocoPhillips received three expansions designed to improve step-out activities at the Colville River unit. The sixth expansion included a bundle of leases between the Colville River unit and the Greater Mooses Tooth unit. The seventh expansion included a single federal lease in the center of the current Colville River unit.

The fifth expansion was more complicated, involving a deal with another leaseholder in the region followed by long deliberations between ConocoPhillips and state officials.

The expansion covers a large patch of acreage south of the unit, previously known as the Titania prospect and more recently known as the Tofkat unit and the Putu prospect.

Brooks Range Petroleum Corp. confirmed the presence of oil on the leases with an exploration program in 2008 but never developed the prospect. The state initially rejected an attempt by Brooks Range Petroleum to transfer the acreage to ConocoPhillips, only to reconsider.

Earlier this year, the state rejected a new plan of exploration from ConocoPhillips unless the company put forth $14 million in bonds and other payments, drilled an exploration well during the 2016-2017 season and a committed to a future development program.

ConocoPhillips and ASRC Exploration LLC reached a deal with the state in August 2017 that would allow ConocoPhillips to retain the leases, pending certain work commitments.

ConocoPhillips must drill an exploration well in the leases by May 31, 2018. Then, by Aug. 15, 2018, the company must announce plans for drilling a second well into the Nanushuk formation and must provide a $3 million bonus bid replacement payment.

The company must test the second well by May 31, 2020, and, if warranted, announce development plans by Aug. 14, 2020. If development is warranted, the company must make a second bonus bid replacement payment of $4 million (with a reduction possible in certain circumstances) and add the region to its Colville River unit plan of development.

Alpine satellites

In its most recent Colville River unit plan of development, ConocoPhillips referred to "other opportunities" at the Alpine participating area and at the other Alpine satellites: Fiord, Nanuq and Qannik. But those opportunities are confidential, at the moment.

ConocoPhillips is not planning any new drilling at the Fiord-Nechelik participating area or at the Fiord-Kuparuk participating area at CD-3 over the coming year, aside from a re-drill of the existing but "collapsed" CD3-111 well. The operation was sched-

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CONOCOPHILLIPS ALASKA

CONOCOPHILLIPS *continued from page 30*

uled for the first quarter of this year. The project includes plans to fracture-stimulate the new well.

At the Nanuq participating area at the CD-4 pad, ConocoPhillips is considering several potential rotary wells and coiled tubing drilling sidetracks over the coming year.

The list of potential drilling candidates was kept confidential in the plan of development.

ConocoPhillips is also considering several potential rotary wells and coiled tubing drilling sidetracks at the Qannik participating area at CD-2 over the coming year and has also kept the list of potential drilling targets confidential in its plan of development.

Altogether, the Colville River unit produced 51,100 bpd and 18.3 million barrels total in 2014, 50,500 bpd on average and 18 million barrels total in 2015 and 58,600 barrels per day and 20.6 million barrels total in 2016, according to the company, reflecting the strong production growth connected to the ongoing CD-5 drilling program.

Greater Mooses Tooth

ConocoPhillips is currently working on three projects at the Greater Mooses Tooth unit, in the National Petroleum Reserve-Alaska, each at a different stage in its development.

During a second quarter earnings teleconference for investors in late July 2017, the company announced that it had completed "key infrastructure components" at the GMT-1 development and expected to bring project into production in late 2018, as scheduled.

The approximately $900 million GMT-1 project includes a drilling pad, a 7.7-mile road and associated infrastructure and pipelines, and an initial drilling program of nine development wells. The GMT-1 pad will have capacity for as many as 33 wells.

The GMT-1 pad will sit at the eastern edge of the unit, about nine miles west of the CD-5 pad at the Colville River unit. Oil will be processed through existing Alpine facilities.

The company expects peak production of 30,000 barrels per day.

As the GMT-1 project moves toward start-up, ConocoPhillips is working through the early permitting stages of a potential GMT-2 development, eight miles west of GMT-1.

If sanctioned, the approximately $1 billion GMT-2 pad could come online in late 2020 and produce some 30,000 barrels per day at its peak, according to the company.

The U.S. Bureau of Land Management began its 18-month scoping review of the project in July 2016. In early 2017, the Native village of Nuiqsut asked the federal agency to delay consideration of the GMT-2 project to address some local environmental concerns.

In early 2017, ConocoPhillips announced a major oil discovery at the western edge of the unit, associated with the Tinmiaq No. 2 and No. 6 exploration wells drilled in early 2016.

The Willow prospect could potentially hold as much as 300 million barrels of recoverable oil. The prospect could be developed either as an Alpine satellite or as a standalone project with independent facilities. A satellite would likely produce between 40,000 and 50,000 bpd while an independent field could reach 100,000 bpd.

ConocoPhillips commissioned a 3-D seismic survey over the Greater Mooses Tooth unit earlier this year to collect more information about the geology of the Willow region. The company is planning expanded exploration drilling in the Willow region for this winter.

In February 2017, ConocoPhillips offered 2023 as an estimated timeframe for bringing Willow online, but acknowledged the risk of permitting and regulatory delays. The company recently established a special project team to evaluate development options.

The Bear Tooth unit remains in the early exploration stage.

ConocoPhillips drilled the Cassin No. 1 well at the federally managed unit to the northwest of the Greater Mooses Tooth in 2013 to meet a work commitment. The company announced a "new oil discovery" from the "wildcat" but has offered no details about the well since.

Developing the GMT-1 pad and the Willow prospect would provide ConocoPhillips with a way to reach Bear Tooth, continuing its decades-long westward step-out strategy. ●

Contact Eric Lidji at ericlidji@mac.com


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Eni favors exploration at Nikaitchuq

The pending Nikaitchuq North project is taking precedence over several projects to expand development

By ERIC LIDJI
For Petroleum News


WHITNEY GRANDE

A year ago, Eni US Operating Co. Inc. was hoping to end its drilling suspension at the Nikaitchuq unit in early 2017, pending an improvement in the price of crude oil. Even though oil prices improved some in late 2016, the rise was apparently too slight and too uncertain for Eni. The company maintained its drilling suspension through the first half of this year and delayed any new development drilling until mid-2018 at the earliest.

Instead of development drilling, the Italian-based major is planning a technologically complex offshore exploration program this winter, targeting federal acreage north of its existing Spy Island drill site. The results of the one-to-two-well Nikaitchuq North exploration project will guide development activities at Spy Island in the years to come.

Until then, Eni plans to continue its ongoing workover activities at both of its drilling pads at Nikaitchuq — the onshore Oliktok Point Pad and the offshore Spy Island drill site.

The company appears to be committed to the shift in strategy.

NAME OF COMPANY: Eni Petroleum
COMPANY HEADQUARTERS: Eni US Operating Co. Inc, Houston, Texas
ALASKA OFFICE: 3800 Centerpoint Dr., Ste. 300, Anchorage, Alaska 99503
TOP ALASKA EXECUTIVE: Whitney Grande, Alaska Eni representative
PHONE: 907-865-3300 • **PARENT COMPANY WEBSITE:** www.eni.it

Earlier this year, it released and demobilized Nabors rig 245, which had been working at the North Slope unit since at least early 2010. And the company contracted the new Nordic Calista Rig No. 4, which was scheduled to arrive at Nikaitchuq this fall to begin workover activities in the spring.

Under the most recent plan of development, the Nordic Calista Rig No. 4 would begin workover activities at the Oliktok Point pad in May 2018 and move to Spy Island at a later date. Additionally, Eni plans to begin converting eight existing single lateral wells at Spy Island into multilaterals and drilling three new wells no sooner than July 2018.

In preparation for the ultra-extended reach wells in the Nikaitchuq North program, Eni commissioned "major upgrades" to Doyon rig 15. It is unclear whether the company also intends to use the rig for the three new development wells in its proposed 2018 program.

The Nikaitchuq unit includes 11 leases covering approximately 21,000 acres in state-owned waters of the Beaufort Sea, immediately north of the Kuparuk River unit.

The Nikaitchuq unit produced approximately 8.3 million barrels in 2014, 8.9 million barrels in 2015, 8.7 million barrels in 2016 and 3.8 million barrels through the first half of this year, according to the Alaska Oil and Gas Conservation Commission. Cumulative production was 39.5 million by the end of June 2017.

Earlier plans

Before sanctioning the Nikaitchuq North project, Eni was considering several options for expanding its existing operations at the North Slope unit, north of the Kuparuk River unit.

After acquiring Nikaitchuq through purchases in 2005 and 2007, Eni undertook a series of administrative tasks to improve the economics of the unit — mostly adding leases and entering a royalty relief program to hedge against low oil prices — and sanctioned a $1.45 billion development program in January 2008. The company expected to bring the unit online in late 2009, but various delays pushed the actual date of first oil to early 2011.

Eni completed its initial Oliktok Point pad drilling program in 2012 and shifted to continuous drilling at the Spy Island drill site. The Spy Island program was still underway in late 2015, when Eni suspended new drilling and reduced its workforce by 10 percent.

Prior to the suspension, Eni had been considering several opportunities for expanding development at the unit beyond its initial plans. The company completed its "West Extension" in 2014 and started its "East Extension" in 2015, before the shutdown.

The company drilled the first well dedicated exclusively to evaluating future N sand development, after focusing exclusively on the O sands of the Schrader Bluff formation.

In previous years, Eni also floated the possibility of developing the Sag River formation at the unit. Sag River oil is deeper and generally lighter than Schrader Bluff oil, but the formation was "plagued with poor quality reservoir rock" and would be "marginal at best unless there are significant advances in stimulation or enhanced oil recovery technology," according to the company. In a July 2014 plan of development, Eni said it intended to submit a proposal for a Sag River development to upper management within 18 months, but the company omitted the Sag River in its 2015, 2016 and 2017 plans of development.

Under the most recent plan of development, the Nordic Calista Rig No. 4 would begin workover activities at the Oliktok Point pad in May 2018 and move to Spy Island at a later date.

In early 2013, Eni drilled the first multilateral well at Nikaitchuq. The SP22-FN1 from the Spy Island drill site had four laterals with lengths between 1,600 and 2,000 feet.

Starting in mid-2013, Eni began adding laterals to existing wells. The campaign lasted through May 2014 and added eight laterals to select wells at the Oliktok Point pad. The laterals increased the amount of drainage from the OA sands and included "alternating undulations through the OA1 and OA3 sand layers as compared to the original laterals."

And in the third quarter of 2013, Eni began incorporating a second lateral into all new production wells being drilled from the Spy Island drill site, which yielded five dual lateral wells by the time the company suspended drilling operations at the end of 2015.

In a plan of development for 2017, Eni proposed six wells from the Spy Island drill site — one producer (SP03-FN9), two injectors (SI02-SE5 and SI06-FN8) and four laterals (SP33-W3L1, SP30-W1L1, SP16- FN3L1 and SP27-N1L1) added to existing wells. A future phase of the project would convert as many as eight existing wells to multilaterals.

Eni is continuing to list those wells as priorities for its 2018 development program. But instead of pursuing those wells over this past year, Eni has been conducting workovers. ●

Contact Eric Lidji at ericlidji@mac.com

A new plan for Exxon at Point Thomson

State official requires the company to file revisions to plan to expand condensate production

By ERIC LIDJI
For Petroleum News

CORY QUARLES

NAME OF COMPANY: Exxon Mobil Corp.
COMPANY HEADQUARTERS: Irving, Texas
ALASKA OFFICE: 3301 C St., Ste. 400, Anchorage, AK 99503
PHONE: 907-561-5331
TOP ALASKA EXECUTIVE: Cory Quarles, Alaska production manager
COMPANY WEBSITE: www.exxonmobil.com

ExxonMobil Alaska Production Inc. started production from the Point Thomson unit in April 2016 after decades of deliberation and litigation and years of construction. And as this edition of The Producers was going to print, a new debate was emerging at the unit.

Earlier this year, the local subsidiary of the global energy giant reluctantly proposed a plan to expand condensate production at the eastern North Slope unit and to deliver the resulting gas to the Prudhoe Bay unit. Although the company would prefer to sell its gas through a "major gas sale" associated with a pipeline project, it detailed a plan to expand condensate production, as required under the terms of a 2012 settlement with the state.

But in late August 2017, state Division of Oil and Gas Director Chantal Walsh denied the expansion plan, giving Exxon until the end of October 2017 to submit a suitable revision.

The point of contention was a clause that subjected the eventual sanctioning of the expansion project to "commercial negotiations and a decision to fund," according to the state, meaning that the working interest owners could ultimately decide not to proceed.

In its proposal, Exxon planned to quintuple its processing facilities, to build a new natural gas pipeline between Point Thomson and Prudhoe Bay, and to drill three new development wells and convert two existing injectors into production wells. The larger facilities would require an expansion of an existing drilling pad at the unit and scrapping portions of the Initial Production System that the company brought online in April 2016.

Under the terms of a development plan submitted to the state in late June 2017, Exxon said it would spend the next two and a half years advancing permitting, design and engineering work and commercial negotiations in order to have a detailed project to submit to its partners for a final decision about sanctioning in late 2019. The company noted that the work it was describing in the plan was not a commitment to the project.

Even so, according to the plan, an Exxon project team has already been studying ways to leverage existing permitting and design work toward the project, has met with the U.S. Army Corps of Engineers to describe the new project and has started negotiating the commercial agreements needed to connect the Point Thomson and Prudhoe Bay units.

According to the state, though, any plan for expanding condensate production is governed by the terms of the 2012 settlement, which requires the company to "begin engineering and permitting" during the 2017-2019 plan of development cycle, and requires any plan to include "work plans for evaluation and selection of an option for development."

IPS shortcomings

The plan of development Exxon submitted earlier this year included elements pertaining to the existing Initial Production System, as well as the proposed expansion project.

The state accepted the newest plan of development for the Initial Production System but accused the company of failing to meet several commitments outlined in the settlement.

First, condensate production from the Initial Production System at the Point Thomson unit is below an agreed-upon target of 10,000 barrels per day. Condensate production has reached 10,000 barrels on specific days since Exxon brought the unit into production in April 2016, but average daily production over that time has remained short of the goal.

According to the state, the company blamed the shortfall on "difficulties with its gas injection compressor." In a technical meeting with the state, officials from the company "provided additional detail about the compressor and its design flaws and difficulties in relation to this reservoir," and told division staff "it was conducting maintenance or repairs on the compressor during periods when production ceased or decreased."

"Exxon did provide an extensive explanation of its problems with the compressor and the Division remains hopeful that those problems are now resolved and that Exxon will soon meet its production rate obligation," Walsh wrote in the August 2017 decision.

Second, the state said that the Initial Production System plan of development failed to propose any debottlenecking work, as required under the terms of the settlement.

Third, the state said that Initial Production System plan of development failed to address a proposed East Pad and associated wells, as required under the terms of the settlement.

Expansion plans

If the issue of committing to work is resolved, the actual plan will likely satisfy.

Under its plan, Exxon would expand Point Thomson facilities to handle peak production greater than 50,000 barrels of condensate per day and would deliver 920 million cubic feet per day to Prudhoe Bay along a new 32-inch pipeline running 62.5 miles between the two units. The gas shipments would be used to enhance oil recovery from the Ivishak reservoir at the Prudhoe Bay unit, where Exxon is the largest working interest owner.

The proposed scope of the expansion project, particularly the gas deliveries, "reflects preferred operation during the period of injection into Prudhoe Bay while also installing necessary infrastructure for a potential (major gas sale)," Exxon wrote in its plan.

To accommodate the desired increase in production, Exxon would drill two new production wells from the Central Pad at the Point Thomson unit and one new disposal well, and it would convert the PTU-15 and PTU-16 injection wells to production. The existing PTU-17 well would remain on production, for a total of five production wells.

The additional processing equipment, wells and pipeline connections would likely require an expansion at the southwest corner of the 50-acre Central Pad, according to Exxon.

The expansion system would be able to use a "majority" of the existing Initial Production System utilities, but most of the existing processing facilities would be "mothballed."

The Initial Production System currently produces condensate and natural gas from three Point Thomson wells, cycles the gas back into the Point Thomson reservoir and delivers the condensate to the trans-Alaska oil pipeline along the Point Thomson Export Pipeline.

The system can cycle some 200 million cubic feet of gas per day through the reservoir and ship 10,000 barrels of condensate per day. In its most recent plan of development, Exxon claimed that the system briefly exceeded both of those figures on Dec. 20, 2016.

The expansion system would be able to use a "majority" of the existing Initial Production System utilities, but most of the existing processing facilities would be "mothballed."

History

Point Thomson is one of the oldest stories on the North Slope.

The original leases were issued around 1965. Exxon discovered oil in the area in 1975 and natural gas in 1977 and formed the Point Thomson unit later that same year.

Exxon and other companies had drilled 17 wells at the unit by 1983, and the results of those wells spawned a debate about the best way to develop the field. Specifically, the company and the state disagreed about the benefits of producing condensate or gas.

Believing Point Thomson was ready for development, the Alaska Department of Natural Resources put the unit into default in 2005 and terminated the unit in late 2006.

The decision launched several years of lawsuits between the state and the company. A court-ordered settlement in early 2012 created a timetable for Exxon to bring the Point Thomson unit into production by early 2016 and for expanding development later.

The Initial Production System was the first part of that timetable. The expansion project is the second part. A future North Slope gas pipeline project remains uncertain. ●

Contact Eric Lidji at ericlidji@mac.com

Furie blames state for lack of drilling

Budgetary standoff and lack of tax credit funding prompt company to postpone Kitchen Lights work

By ERIC LIDJI
For Petroleum News

After a summer of uncertainty at the Kitchen Lights unit, Furie Operating Alaska LLC recently blamed state fiscal policy for thwarting its drilling activities for this year.

The local independent planned to use the Randolph Yost jack-up rig this summer to complete the KLU No. A-1 well at the offshore unit in Cook Inlet. The development well was required to meet the terms of a gas supply agreement with Enstar Natural Gas Co. Inc.

In late September 2017, though, the utility asked state regulators to amend the terms of the contract, to give Furie until July 31, 2018, to complete the KLU No. A-1 well. For a time, Furie stayed silent about the status of the project and the possible reasons for delay.

But in a plan of development submitted to state officials in early October, the local independent blamed its lack of any new development or exploration drilling at Kitchen Lights this past year on "the lack of any meaningful appropriation to the oil and gas tax credit fund for the purchase of Alaska oil and gas production tax credit certificates."

The Randolph Yost rig was fully staffed for drilling operations at Kitchen Lights as early as April 2017, according to Furie. But the company had to delay the purchase of certain long-lead items pending the results of state budget negotiations over this past summer.

BRUCE WEBB

NAME OF COMPANY:
Furie Operating Alaska LLC
COMPANY HEADQUARTERS:
League City, Texas
ALASKA OFFICE: 1029 W. Third Ave., Ste. 500
Anchorage, AK 99501
TOP ALASKA EXECUTIVE: Bruce Webb, vice president
TEXAS TELEPHONE: 281-957-9812
ALASKA TELEPHONE: 907-277-3726 • **WEBSITE:** www.furiealaska.com

The ultimate decision to again underfund outstanding certificates meant that "Furie did not receive the funds it had relied on for its 2017 operations," the company wrote.

In addition to the financial uncertainty, Furie blamed its inability to drill on the protracted budgetary standoff over the summer, which threatened to shut down government services.

Lawmakers passed a capital budget on July 27, two weeks after a tugboat required for operating the Randolph Yost rig went into dry dock and left for Singapore on July 13.

Furie needed the anchor handling tugboat to set the jack-up rig in place. According to the company, no suitable replacement vessel could be found in Alaska. The Randolph Yost rig remained staffed until mid-August, when Furie learned that the boat would not return until October, just before the end of the open-water drilling season in the Cook Inlet.

An alternate plan to bring a replacement vessel from the Gulf of Mexico proved to be too expensive and time-consuming in the time remaining, leading Furie to cancel its program.

"In sum, the lack of a timely resolution regarding funding for DOR to purchase tax credits delayed operations until the anchor handling tug boat was no longer available, and it was not returning to Alaska until the very end of the drilling season," Furie wrote.

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FURIE *continued from page 39*

The two previous gubernatorial vetoes that cut funding for buying tax credits "created significant uncertainty for investors, making it harder and more expensive for Furie and other small, independent producers to secure crucial funds needed for drilling and completion programs" and "essentially gutted Furie's sourced budgeted funds for 2016."

"Furie has invested hundreds of millions of dollars in exploring and developing the KLU (Kitchen Lights unit) and has a very substantial amount of tax credit certificates in the queue awaiting purchase by the state," the company wrote in its plan. "These certificates are a key component to funding further exploration and development activities in the KLU and were relied on by Furie when putting together its work program and budget."

Upcoming plans

The Kitchen Lights unit is currently producing from two wells: the initial KLU No. 3 discovery well drilled in late 2015 and the KLU No. A-2A well drilled in 2016.

Furie began drilling the KLU No. A-1 well last year and planned to finish this year.

As part of its work this year, Furie removed a Composite Bridge-Plug Setting Tool from KLU No. 3, allowing the well to produce from both the Beluga and Sterling formations.

For the coming year, Furie is proposing a two-well program.

The company first intends to complete the KLU No. A-1 well "if advisable based on logs, data and market conditions" and then plans to drill a new development well at the unit.

The new development well would also be in the Corsair block — one of four exploration blocks at the unit and the site of all current development. The new well would target a Sterling interval from 6,964 feet to 6,998 feet measured depth in the KLU No. 3 well, "unless interpretations from the shallower data in a well indicate that producible hydrocarbons are unlikely to be found by drilling to that equivalent horizon depth."

Alternately, the company said it might postpone the development well in favor of drilling a new exploration well or re-entering and deepening the existing KLU No. 4 well.

The company previously mentioned these two options — a new Sterling development well or an exploration program — in an amended plan of development submitted May 2017.

In its plan, Furie also referenced its earlier exploration plan, which detailed proposed exploration well locations throughout the unit on a timeline between now and 2021.

An increased flow rate test on the KLU No. 3 and KLU No. A-2A wells in August 2017 produced at a combined rate of 31 million cubic feet per day, according to Furie.

The demands of the Enstar contract range from 10 million cubic feet to 22 million cubic feet per day. A contract with Homer Electric Association requires deliveries between 12 million to 18 million cubic feet of gas per day, depending on the time of year.

Earlier this year, the Regulatory Commission of Alaska approved a gas supply agreement between Furie and Chugach Electric Association Inc. The agreement included interruptible and firm supplies components. The interruptible supply began immediately.

The firm supply portion begins on April 1, 2023. It requires Chugach to purchase at least 5 million cubic feet of natural gas per day, totaling about 1.8 billion cubic feet per year. Starting in the seventh year of the contract, Chugach can purchase an additional 2 million cubic feet per day. Both parts of the gas supply agreement run through March 31, 2033. ●

Glacier being cautious at four fields

Workover projects taking precedence over development and exploration for now

By ERIC LIDJI
For Petroleum News

Glacier Oil & Gas Corp. took a cautious approach to development after it acquired the Alaska assets of Miller Energy Resources Ltd. in a bankruptcy case in early 2016.

The current economic situation has increased that caution.

After rightsizing its portfolio and deferring some exploration work, the local independent drilled just two sidetracks across its four Alaska properties over the past year, choosing instead to focus on workover activities and a major infrastructure consolidation project.

Through its subsidiary Cook Inlet Energy LLC, Glacier operates the West McArthur River and Redoubt units on the west side of Cook Inlet and the North Fork unit in the southern Kenai Peninsula. Through its subsidiary Savant Alaska LLC, Glacier operates the Badami unit on the eastern North Slope. Those projects make Glacier the only operator aside from Hilcorp Alaska LLC with production in Alaska's two major basins.

The Redoubt unit

Since the end of the bankruptcy case, Glacier has focused much of its development resources on its two west side properties: the Redoubt and West McArthur River units.

Glacier drilled the 14,849-foot slightly deviated RU No. 7B sidetrack of the RU 7A well in late 2016, and later conducted hydraulic fracture stimulation of the sidetrack. The results of the project will determine future projects, which could include replacing electric submersible pumps at the RU No. 1A and RU No. 5B wells and hydraulically fracturing the RU No. 1A, RU No. 5B and RU No. 9 wells, according to the company.

Glacier drilled the 16,482-foot deviated RU No. 3A sidetrack in May 2017. The injection well will be used to improve oil production. The company is also reviewing its waterflood program to determine if it should convert non-producing wells to injection.

Also during the past year, Glacier swapped out a gas-fired boiler at the Osprey platform with an electric heating system that uses excess power from the Kustatan Production Facility. Longer term, the company wants to begin a delineation program in the Central, Southern and Northern fault blocks. The company is considering an exploration program north of the Northern fault block "when favorable economic conditions warrant."

Redoubt produced 345,801 barrels of oil in 2015, 233,416 barrels in 2016 and 149,786 barrels in the first six months of 2017, according to the Alaska Oil and Gas Conservation Commission. Cumulative production through June 2017 was some 4 million barrels.

The West McArthur River unit

In the biggest West McArthur River unit development, Glacier decommissioned the West McArthur River Production Facility and shifted over to the Kustatan Production Facility.

While as many as 2 million barrels of recoverable oil remain at the West McArthur River unit, according to the company, the aging facility was reaching the end of its useful life.

NAME OF COMPANY: Glacier Oil & Gas
COMPANY HEADQUARTERS: 4601 Washington Ave., Ste. 220 Houston, Texas 77002
ALASKA OFFICE: 601 West Fifth Ave., Ste. 310 Anchorage, AK 99501
PHONE: 907-334-6745
TOP ALASKA EXECUTIVE: Leland Tate, COO

GLACIER

The newer and more efficient Kustatan facility can process some 25,000 barrels of fluid per day and can store 50,000 barrels. The Redoubt unit is only producing some 1,000 barrels per day, leaving plenty of room for West McArthur River unit oil production.

The consolidation project involved many technical considerations but also some administrative ones, such as receiving permission to use multi-phase flow meters. The meters allow the company to jointly process oil from the West McArthur River

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GLACIER OIL & GAS *continued from page 41*

unit and the Redoubt unit through a single facility and to tabulate the two streams separately.

In addition to the consolidation project, Glacier conducted a four-well workover program. The company swapped out jet pumps for electric submersible pumps at the WMRU No. 2B, WMRU No. 5, WMRU No. 6 and Sword wells, which reduced the need for power fluid.

The company also perforated additional zones in WMRU No. 2B and WMRU No. 5. The workover program slowed production somewhat in 2016 but added "significant" production at the unit after the wells resumed operations, according to Glacier. The company said it would continue conducting workover activities over the coming year.

In a recent development plan and other permitting documents, Glacier said it would resume exploration activities at the unit this year by returning to the long-delayed Sabre well. The company deferred the well in May 2017, blaming fiscal uncertainty in the state.

The West McArthur River unit produced almost 479,488 barrels of oil in 2015, 360,373 barrels in 2016 and 234,314 barrels in the first half of 2017, according to the Alaska Oil and Gas Conservation Commission. Cumulative oil production through June 2017 was more than 14.8 million barrels. The unit produced 194.2 million cubic feet of natural gas in 2015, 138.6 million cubic feet in 2016 and 62.1 million cubic feet in the first half of 2017. Cumulative gas production through June 2017 was more than 3.8 billion cubic feet.

The North Fork unit

In announcing its plans for the North Fork unit, Glacier said it would pursue a series of "small ball" projects, rather than attempting a major development program at the unit.

A plan of development submitted in December 2016 listed various efforts to improve production from existing wells, including the installation of additional compression and separation facilities, the reprocessing of a previous seismic survey over the area and planned workover operations on the existing NFU No. 14-25 and NFU No. 41-35 wells.

As for its ongoing efforts to "fully delineate and develop all fault blocks within the current unit" through development drilling, Glacier said the work would resume "as appropriate based on data review and market conditions." The company specifically mentioned a NFU No. 42-35A sidetrack and a NFU No. 22-26 or a NFU No. 14-26 well.

The company is also considering several major infrastructure plans.

One is to expand the existing North Fork pad to accommodate new compression and dehydration equipment. Another is to build a second drilling pad to better develop the reservoir. A third is to drill outside the North Fork Gas Pool No. 1 participating area.

Glacier attributed its cautiousness to low oil prices and a constrained natural gas market.

The scaled-down development plan also followed a year when Glacier was unable to fulfill the work commitments made by its predecessor before the bankruptcy case.

Through Cook Inlet Energy, Miller had committed to sidetracking the NFU No. 42-35, drilling the NFU No. 14-26 well and potential drilling another delineation well.

Glacier was unable to complete those tasks, citing the bankruptcy case, oil prices and market conditions such as consolidation, warmer winters and fewer big users. Instead, the company reprocessed existing seismic and perforated new zones in existing wells.

In a letter approving the current development plan, Division of Oil and Gas Director Chantal Walsh called the difference between the proposed development plan and the actual work "significant" and added that a constrained market was not "force majeure."

The North Fork unit produced 3.2 billion cubic feet of natural gas in 2015, 2.2 billion cubic feet in 2016 and 1.1 billion cubic feet through the first half of 2017, according to the AOGCC.

Cumulative production through June 2017 was more than 16 billion cubic feet.

The Badami unit

Glacier recently made a shift in its strategy at the Badami unit.

In its plan of development from April 2017, the company announced plans for an exploration well and for infill drilling away from the existing unit development, rather than drilling new development wells and stimulating existing development wells.

Glacier inherited the Badami unit from Miller Energy, which acquired operator Savant Alaska LLC and its 67.5 percent working interest in the unit in the latter half of 2014.

Around the time of the acquisition, Savant was planning to

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Hilcorp continues Cook Inlet dominance

The leading player in the Cook Inlet region is facing different situations at different areas in its portfolio

By ERIC LIDJI
For Petroleum News

Hilcorp Alaska LLC has been the dominant producer in the Cook Inlet basin since it arrived in Alaska five years ago, and its dominance seems to increase with each year.

The local subsidiary of the Texas-based independent currently operates about 20 fields and units — a number that occasionally fluctuates due to acquisitions and consolidations.

DAVE WILKINS

NAME OF COMPANY: Hilcorp Energy Co.
COMPANY HEADQUARTERS: Houston, Texas
ALASKA OFFICE: 3800 Centerpoint Dr., Ste.1400 Anchorage, AK 99503
TELEPHONE: 907-777-8300
TOP ALASKA EXECUTIVE: Dave S. Wilkins, senior vice president, Hilcorp Alaska
COMPANY WEBSITE: www.hilcorp.com

On the west side of Cook Inlet, Hilcorp operates the Ivan River unit, the Lewis River unit, the Pretty Creek unit, the Stump Lake unit and the Beluga River unit. Offshore, the company operates the North Cook Inlet unit, the Granite Point unit, the Middle Ground Shoal unit, the Trading Bay unit and the North Trading Bay unit and associated McArthur River field. In the southern Kenai Peninsula, the company operates the Deep Creek unit, the Ninilchik unit and the Nikolaevsk unit. In the northern

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HILCORP *continued from page 43*

Kenai Peninsula, the company operates the Birch Hill unit, the Swanson River unit, the Beaver Creek unit, the Sterling unit, the Kenai unit and the Cannery Loop unit. Some of those properties are inactive and the company is in the process of determining whether to revive or relinquish them.

Operating such a large number of properties has allowed Hilcorp to connect certain fields in new ways, leading to regional stories throughout the basin. On the west side, the company is looking for ways to maintain production from marginal properties near one of the most important field in the basin. Offshore, the company is consolidating neighboring properties to create efficiencies. In the southern Kenai Peninsula, the company is using exploration to expand existing development. In the northern Kenai Peninsula, the company is steadily working to revive some of the oldest active fields in the basin.

All those stories fall within a larger story. In recent years, Hilcorp has scaled back its development activities across the Cook Inlet basin in response to the economic climate.

The extent of those holdings have also allowed Hilcorp to consolidate certain midstream initiatives in Cook Inlet. The company recently asked the Regulatory Commission of Alaska for permission to ship oil from west to east, beneath Cook Inlet. The $75 million Cross Inlet Extension Project would bypass the Drift River oil terminal, allowing the company to reduce the use of oil tankers in Cook Inlet.

West side

By taking over operatorship of the Beluga River unit from ConocoPhillips Alaska Inc. in early 2016, Hilcorp created an opportunity for employing a new strategy at its west side properties.

The four other units that Hilcorp operates in the region — Ivan River, Lewis River, Pretty Creek and Stump Lake — are all marginally economic, according to the company, and have received the lowest investment of any region in the Hilcorp portfolio in Cook Inlet.

The company did not drill any wells or conduct any workover activities at the units in 2016 and is not planning any development work for the current year. For some time, the company has been planning a comprehensive study to determine the future of the region.

The Ivan River unit produced some 450 million cubic feet of gas in 2015, some 320 million cubic feet in 2016 and more than 130 million cubic feet in the first half of 2017, according to figures provided by the Alaska Oil and Gas Conservation Commission.

Cumulative production through June 2017 was 85.9 billion cubic feet.

The Lewis River unit produced 336 million cubic feet in 2015, 130 million cubic feet in 2016 and 66.2 million cubic feet in the first half of 2017, according to the AOGCC.

Cumulative production through June 2017 was 15.3 billion cubic feet.

The Pretty Creek unit produced 0.85 million cubic feet of gas in 2015, 0.32 million cubic feet in 2016 and 1.5 million cubic feet in the first half of 2017, representing a noticeable production increase. Cumulative production through June 2017 was 9.5 billion cubic feet.

The regional study will have the greatest impact on the Stump

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hydraulically fracture two existing Badami wells and drill two new wells at the unit. The project was postponed in late 2014 and early 2015 because the company was unable to get equipment to Badami in time to complete the activities before the end of the open water season in the Arctic.

In a plan of development submitted in early 2016, Glacier — through Savant — told the state it was "unable to justify the expense" of the development program at the moment and would pursue the stimulation and drilling projects "as economic conditions warrant."

Instead of conducting major development activities, Glacier performed minor workover operations at the B1-11A and B1-36 wells. The operations identified 321 feet of additional zones in need of perforation, which the company performed in November 2015. The work increased production by 369 barrels per day, according to the company.

Glacier also told the state it was undergoing internal evaluations to determine what opportunities exist. Those evaluations included a geologic and geophysical review of the "Badami and Killian sands and associated producing wells," as well as "historical wells and field structure." The company also reviewed potential targets outside the Badami Sands participating area, including the Killian Sands on the eastern end of the unit.

The reviews identified "several new target 'pods' of interest," according to Glacier.

The company said it was planning to use Rig 36 to drill an exploration well in the Starfish prospect. The well would target the Badami and Killian sands southwest of the current development within the Badami Sands participating area. The company also said it was considering other drilling opportunities outside of the existing participating area.

As for development within the Badami Sands participating area, Glacier said it would resume its drilling and stimulation program "as economic conditions warrant."

Badami produced 346,998 barrels of oil in 2015, 363,288 barrels in 2016 and 159,659 barrels through the first half of 2017, according to the Alaska Oil and Gas Conservation Commission. Cumulative oil production through June 2017 was 7.9 million barrels. ●

Contact Eric Lidji at ericlidji@mac.com

Lake unit.

Hilcorp suspended operations at the unit in 2012, when the company encountered mechanical issues as it was attempting to add perforations to the SLU 41-33RD well.

When it assumed operatorship of the Beluga River unit, Hilcorp told the state that the larger unit created new opportunities for reviving production the Stump Lake unit. Without such a "critical mass" of projects in the region, "the economic life of the Stump Lake unit has likely passed," the company added at the time. But after completing a state-mandated field study at Stump Lake, Hilcorp "concluded that the conventional life of this legacy field has reached its economic limit," according to a March 2017 plan of development.

Even so, the company decided to include the Stump Lake unit in its regional study and committed to restarting production from the unit by the third quarter of this year. "If unit production is not resumed by said date, Hilcorp commits to plugging and abandoning of SLU 41-33RD" in the 2018 plan year, the company wrote in its plan of development.

The state Division of Oil and Gas determined that the Stump Lake unit plan of development was incomplete as written and asked the company for more detailed information about its plan to restore production by the third quarter of the year.

Even if the company decides to permanently end operations at Stump Lake, the comprehensive study also presents opportunities for the three remaining units.

Hilcorp conducted a workover program at the Beluga River unit in 2016, temporarily bringing the 244-04 well online to diagnose a range of maintenance requirements and evaluating the 224-34 and 214-26 wells as candidates for artificial lift in the future.

The company did not drill any wells or sidetracks at Beluga River during its first year as operator and has not made any firm drilling plans at the unit for the coming year.

The Beluga River unit produced 21.2 billion cubic feet of gas in 2015, 18.0 billion cubic feet in 2016 and 7.7 billion cubic feet in the first half of 2017, according to the AOGCC.

Cumulative production through June 2017 was 1.34 trillion cubic feet.

Offshore

Hilcorp currently operates six offshore fields and 12 offshore platforms in four clusters throughout the waters of Cook Inlet. The extent of these assets has allowed the company to consolidate neighboring properties and potentially to restart suspended oil platforms.

Several months after taking over as operator at the Beluga River unit from ConocoPhillips, Hilcorp closed on ConocoPhillips' offshore North Cook Inlet unit and its Tyonek platform.

By the time of the closing, ConocoPhillips had already submitted a plan of development for North Cook Inlet for the year. Hilcorp submitted an update to the state in April 2017.

Under the updated program, Hilcorp would not drill any wells or sidetracks nor would it perform any workover operations at the North Cook Inlet unit this year. But the company would conduct a comprehensive field study for future activities, including oil production.

The North Cook Inlet unit has traditionally provided natural gas for the ConocoPhillips-operated Kenai liquefied natural gas facility, which is currently

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semi-idle and for sale.

The North Cook Inlet unit produced 7.3 billion cubic feet of gas in 2015, 5.9 billion cubic feet in 2016 and 3.4 billion cubic feet in the first half of 2017, according to the AOGCC.

Cumulative production through June 2017 was 1.9 trillion cubic feet.

To the south, Hilcorp has combined the Granite Point field and the South Granite Point unit into the Granite Point unit with three platforms — Granite Point, Anna and Bruce.

The company did not drill at Granite Point in 2016 but plans to drill three sidetracks this year — the GP-11-24RD, GP-24-13RD2 and MUCI-02RD sidetracks, according to the most recent plan of development, from March 2017. All three sidetracks would target the Tyonek C7 sands from the Granite Point platform. At the Alaska Oil and Gas Association annual conference on May 31, Hilcorp Alaska Senior Vice President David Wilkins described the wells as a horizontal redevelopment program, scheduled to start in June.


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The Alaska Oil and Gas Conservation Commission issued a permit on July 12 for the company to drill the Granite Point State 22-13RD3 into the Middle Kenai oil pool.

The company performed a workover on the AN-11RD well in 2016 but was unable to return the well to production. The company is planning no workovers at the unit this year.

Hilcorp suspended operations at the Anna platform for several days in April 2017 after personnel discovered a small leak of natural gas condensate from a gas flaring system.

Granite Point produced some 804 million cubic feet of gas in 2015, 791 million cubic feet in 2016 and 323 million in the first half of 2017, according to the AOGCC.

Cumulative gas production through June 2017 was some 135.8 million cubic feet.

Granite Point produced some 0.92 million barrels of oil in 2015, 0.92 million barrels in 2016 and 0.39 million barrels in the first half of 2017, according to the AOGCC.

Cumulative oil production through June 2017 was 152.7 million barrels.

Hilcorp has also consolidated the North Middle Ground Shoal field, Middle Ground Shoal field and South Middle Ground Shoal unit into the Middle Ground Shoal unit.

In requesting consolidation, the company argued that it would maximize operations at Platforms A and C and promote opportunities at the shut-in Baker and Dillon platforms.

The company is planning no drilling or workover activities at Platform A this year but could sidetrack three Platform C wells — C23-26RD, C33-26RD and C34-26RD — later this year or in 2018. The company is planning no work at the Baker or Dillon platforms.

The company reported a notable increase in production from the unit between 2015 and 2016, likely the result of eight workover projects. The company added perforations at the A11-01, A12A-01 and A24-01LE wells at platform A, and performed a variety of projects at C21-23, C22-26RD, C13-13LN, C31-26RD and C42-232 at platform C.

Hilcorp processed a 2015 3-D seismic program last year and plans to continue analyzing the results this year with the plan of identifying future drilling or workover projects.

Middle Ground Shoal produced 0.69 million barrels in 2015, 0.68 million barrels in 2016 and 0.14 million barrels in the first half of 2017, according to the AOGCC.

Cumulative oil production through June 2017 was 203.1 million barrels.

The future of the shut-in Baker and Dillon platforms remains a point of uncertainty.

In its 2016 plans of development for North Middle Ground Shoal and South Middle Ground Shoal, before the units were consolidated, Hilcorp announced plans to restart North Middle Ground Shoal production from the Baker platform to production in 2017 and to conduct a comprehensive reservoir study of the South Middle Ground Shoal unit with the goal of restarting production in 2018, presumably through the Dillon platform.

The company removed both projects from its 2017 plan of development. When the state asked for details, the company said it had no immediate plans to revive the platforms.

For that reason, Division of Oil and Gas Director Chantal Walsh denied the most recent plan of development and forced the company to provide updated plans for the platforms.

In a revised plan, Hilcorp explained that it suspended the Baker and Dillon programs after a gas pipeline disruption upended operations across the entire unit, requiring the company to divert all its resources at the moment toward Platform A and Platform C.

Even so, while plans to restart Dillon platform production remain on-track, albeit hampered by technical and economic problems, the company no longer believes the plan to restart Baker platform production is viable and is diverting those resources to A and C.

The company argued that the interconnectedness of the three Middle Ground Shoal fields justified the decision to consolidate, regardless of the Baker and Dillon platforms.

To the south, the Trading Bay unit and McArthur River field and the North Trading Bay unit remain distinct fields, although their operations and administration are interrelated.

In its most recent plan of development for the Trading Bay unit, from March 2017, Hilcorp announced plans to sidetrack the A-04RD well from the Monopod platform into the nearby North Trading Bay unit. The sidetrack would target the Hemlock and Tyonek G-zone. If successful, the sidetrack would restore production at North Trading Bay.

The plan would require some administrative changes, such as a revision of the unit boundaries or metering requirements, and it leaves open the question of what to do with the shut-in Spark and Spurr platforms at North Trading Bay. There were discussions in previous years of dismantling the platforms. Hilcorp does not believe it is economic to restart production from the two platforms, but does believes that they have value "to support ongoing evaluation and analysis" of potential development oppor-


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tunities.

The company sidetracked the A-27RD2 well in 2016 but deferred plans for drilling the A-20RD2D and A-26RD wells pending a further review of seismic information. The company also deferred three of the four workover projects it had planned for 2016.

The Trading Bay unit produced 1.8 billion cubic feet of gas in 2015, 1.2 billion cubic feet in 2016 and 512 million cubic feet in the first half of 2017, according to the AOGCC.

Cumulative gas production through June 2017 was 79.9 billion cubic feet.

The Trading Bay unit also produced 1.1 million barrels of oil in 2015, 0.8 million barrels in 2016 and 0.32 million barrels in the first half of 2017, according to the AOGCC.

Cumulative oil production through June 2017 was 107.3 million barrels.

In its most recent plan of development for the McArthur River field, in March 2017, Hilcorp announced plans to drill as many as three grassroots wells and four sidetracks over the current development year. The three wells — M35, M36 and M37 — would target the upper West Foreland formation from the Steelhead platform. The four sidetracks — K-06RD2, K-24RD3, K-03RD2 and K-26RD2 — would be at King Salmon platform wells.

Through the first seven months of the year, the company drilled the K-03RD2, K-06RD2 and K-24RD3 sidetracks and the M-06RD, M-28RD and M32RD wells at the field.

The company sidetracked the shut-in K-10RD well, the K-06RD well and the K-10RD well in 2016. A plan to sidetrack the K-25RD well was cancelled due to low quality rock.

The company also worked over one well at the Dolly Varden platform, four wells at the Grayling platform, two wells at the Steelhead platform and three wells at the King Salmon platform. The work mostly involved replacing electric submersible pumps.

The McArthur River field produced 8.9 billion cubic feet of gas in 2015, 7.3 billion cubic feet in 2016 and 3.1 billion cubic feet in the first half of 2017, according to the AOGCC.

Cumulative gas production through June 2017 was 1.2 trillion cubic feet.

The McArthur River field also produced 2 million barrels of oil in 2015, 1.79 million barrels in 2016 and 0.7 million barrels in the first half of 2017, according to the AOGCC.

Cumulative oil production through June 2017 was 641.9 million barrels.

The southern Kenai Peninsula

At its properties in the southern Kenai Peninsula, Hilcorp is using exploration to expand production at existing developments and to protect acreage from automatic contraction.

The company operates three active units in the area: Deep Creek, Ninilchik and Nikolaevsk. The company recently terminated the offshore Kasilof unit after considering and then rejecting a proposal to consolidate its operations into the coastal Ninilchik unit.

The company also operates a considerable number of un-unitized state and private leases throughout the southern Kenai Peninsula, including a cluster south of Anchor Point where the company recently permitted several stratigraphic tests wells at the new Seaview prospect.

In its most recent plan of development for Deep Creek, Hilcorp announced plans to drill between four and six stratigraphic test wells over the coming development year. The results would guide exploration in the Sterling and Beluga formations for 2018 and 2019.

In the plan, Hilcorp once again deferred a project to build the Middle Happy Valley pad or C pad at the unit. "Hilcorp continues to progress plans to drill at Middle Happy Valley and C-Pad (within the Happy Valley PA), but cannot commit to drilling until the operational and economic risk associated with such ex-

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ploratory efforts is reduced." The company also deferred plans to drill a Middle Happy Valley exploration well in 2016.

As proof of its commitment, Hilcorp noted that it conducted seismic programs in 2013 and 2016 and a remote sensing data program in 2015 in the southern end of the unit.

The state has previously threatened to contract the unit unless Hilcorp explores the area.

In its 2016 development year, the company added perforations to the existing HVB-17 well, with production beginning in May 2016. The company also overhauled compression facilities at the existing Happy Valley A and Happy Valley B pads.

The Deep Creek unit produced 2.4 billion cubic feet of gas in 2015, 2.2 billion cubic feet in 2016 and 1.1 billion cubic feet in the first half of 2017, according to the AOGCC.

Cumulative production through June 2017 was 33.5 billion cubic feet.

In its most recent Ninilchik plan of development, Hilcorp announced plans to drill the Kalotsa No. 3 and No. 4 wells at the new Kalotsa pad and later announced plans to drill the Pearl No. 2 well from a new Pearl pad to be built on private leases beyond the unit boundary. If successful, Hilcorp would build Pearl production facilities in early 2018.

The Alaska Oil and Gas Conservation Commission issued a drilling permit for the Kalotsa No. 3 well on March 8, 2017, and the Kalotsa No. 4 well on May 2, 2017, and issued permits for the Pearl No. 1A, Pearl No. 2, Pearl No. 3, Pearl No.4, Pearl No. 5, Pearl No. 6 and Pearl No. 7 stratigraphic test wells in late June and early July 2017.

In September 2017, Hilcorp asked the AOGCC to expand the Ninilchik Beluga/Tyonek gas pool to include the deeper intervals — known as the sub-T142 sands — the company has been testing over the past year with the Kalotsa No. 3 and Kalotsa No. 4 wells.

The Ninilchik unit produced 13.9 billion cubic feet of gas in 2015, almost 11. 5 billion cubic feet in 2016 and 6.1 billion cubic feet in the first half of 2017, according to the AOGCC. Cumulative production through June 2017 was 195.1 billion cubic feet.

The Nikolaevsk unit remains in a holding pattern.

Hilcorp is not planning any new drilling activities at the unit but plans to hydraulically fracture the Tyonek formation in the existing Red well and expects that the workover project will increase unit productivity by 1 million to 3 million cubic feet per day.

The Nikolaevsk unit produced 80.8 million cubic feet of gas in 2015, 54.5 million cubic feet in 2016 and 89.5 million cubic feet in the first half of 2017, according to the AOGCC. Cumulative production through June 2017 was 875.9 million cubic feet.

The northern Kenai Peninsula

At the northern end of the Kenai Peninsula, Hilcorp operates a series of older onshore units that are predominately overseen by the U.S. Bureau of Land Management.

In its most recent plan of development for the Swanson River unit, Hilcorp announced plans to drill one well and perform one workover during the year ending March 2018.

The company plans to drill the SRU 241-33 well and perform a workover on the SCU 44-33 well during the third quarter of this year. (The Swanson River unit and the Soldotna Creek unit started as separate administrative entities but have been managed together since 1963, and some well names at the unit still reflecting those earlier designations.)

The company is currently working on a field-wide shallow gas survey at the Swanson River unit. The goal is to identify remaining reserves above the Hemlock formation. A list of sidetrack candidates "will be vital for economically reaching these smaller/less economic targets" and could influence development activities in the near future.

In the 2016 development year, Hilcorp drilled two wells — SCU 322C-04 and SCU 31B-04 — and completed workover projects at SCU 33-33, SRU 14B-27 and SCU 41A-08.

In its most recent plan of development for the Kenai unit, Hilcorp announced plans to drill as many as six wells in the year ending March 2018, including at least four wells into the Deep Tyonek participating area and two wells into the Beluga/Tyonek gas pool.

The company is also considering two other well projects.

The upcoming development program also includes as many as 25 workover projects at the unit. The program includes as many as 10 coil tubing workovers, five rig workovers and 10 e-line recompletions with an emphasis on restoring older wells to production.

The program is a large increase over activities in the development year ending March 2017, when the company conducted 12 workover projects and did not drill new wells.

The Swanson River unit produced 0.9 million barrels of oil in 2015, 0.74 million barrels in 2016 and 0.32 million barrels in the first half of 2017, according to the AOGCC.

Cumulative oil production through June 2017 was 234 million barrels.

The Swanson River unit also produced 1.9 billion cubic feet of gas in 2015, 3.1 billion cubic feet in 2016 and 2.6 billion cubic feet in the first half of 2017, according to the AOGCC. Cumulative gas production through June 2017 was 2.87 trillion cubic feet.

To the north at the Cannery Loop unit, Hilcorp plans to sidetrack the CLU-10 well this year to the Upper Tyonek and workover the CLU-05RD well to the Upper Tyonek.

Hilcorp is not planning any wells or sidetracks at the Beaver Creek unit this year but expects to conduct a rig workover targeting the Sterling B3 interval at the BCU-25 well.

The company also did not drill any wells or sidetracks at the Beaver Creek unit in 2016 but performed one rig workover targeting five Tyonek intervals at the BCU-23 well.

The Beaver Creek unit produced 6.2 billion cubic feet of gas in 2015, 4.5 billion cubic feet in 2016 and 2.4 billion cubic feet in the first half of 2017, according to the AOGCC.

Cumulative production through June 2017 was 232.3 billion cubic feet.

The Birch Hill and Sterling units are currently suspended.

Hilcorp is planning to restart production from the Birch Hill unit, although the project depends upon completing construction of a surface infrastructure program at the unit.

The program revolves around a plan to remove a plug from the existing Birch Hill 22-25 well, conduct a workover and conduct various well tests. The project requires construction of a snow road and mobilization of a workover rig and testing equipment.

If the well proves to be non-commercial, Hilcorp would plug and abandon the well. If the test is successful, Hilcorp would build a production facility and gas gathering lines to bring the unit into production. The project would take between six and 12 months, with half devoted to planning, permitting and design and the rest going toward construction.

Operating such a large number of properties has allowed Hilcorp to connect certain fields in new ways, leading to regional stories throughout the basin.

But the entire project, including both the test and the potential development, is dependent on "gas market requirements and favorable winter weather conditions," Hilcorp wrote.

In its most recent plan of development for the Sterling unit, Hilcorp proposed a sequential process of plugging and abandoning four existing wells. The process would start with the suspended SU 23-15 well and the shut-in SU 41-15RD well in the third quarter of this year. After plugging and abandoning those two wells, the company would contract the federal, state and privately held acreage from the unit and voluntarily relinquish the leases associated with that acreage, leaving only Cook Inlet Region Inc. leases within 1,500 feet of the remaining two wells at the Sterling pad — SU 43-9X and SU 32-09 — for future production. (A fifth well at the unit — SU 43-09 — remains an active disposal well.)

But the BLM has said it would prefer to terminate the unit, given the inability of Hilcorp to restore production over the past three years. The state did not object to termination. ●

Contact Eric Lidji at ericlidji@mac.com

Hilcorp ramping up North Slope work

Milne Point underway, Duck Island beginning, Northstar up next, Liberty enters public comment period

By ERIC LIDJI
For Petroleum News

Hilcorp Alaska LLC is taking a phased approach to its North Slope properties.

The local subsidiary of the Texas-based independent is several years into its efforts to improve production at the Milne Point unit, just beginning major development work at the Duck Island unit and still involved in preliminary activities at the Northstar unit.

The company is also overseeing activities at the federal Liberty project.

Through its acquisition deal with BP Exploration (Alaska) Inc., Hilcorp owns and operates the Duck Island unit and Northstar unit outright, is the operator and a 50 percent owner of the Milne Point unit and operator and 50 percent owner of the Liberty unit.

Milne Point

The development program at Milne Point is spread across the unit.

According to Alaska Oil and Gas Conservation Commission records, Hilcorp drilled at least nine wells and sidetracks at Milne Point in calendar year 2016: L-47 in February, B-28 and B-29 in March, J-23A in April, J-27 and K-44 in May, J-28 in June, C-15A in July and L-50 in November. The company also performed 16 workovers in 2016.

Through the first half of this year, the company had drilled five wells — J24A in January, B-32 in March, B33 and B-34 in April and B-30 in June. The company also received permits for the new C-45, C-46 and C-47 wells and conducted seven workover projects.

Recent activity at B pad included the B-28 lateral producer and B-29 later injector into the Schrader ND sand, the B-32 lateral producer and B-33 lateral injector into the Schrader NC sand and the B-34 injector into the Ugnu, part of a recent grind and inject project. The J pad program included the J-23A and J-24A sidetrack lateral injectors into the Schrader NB sand and the J-27 and J-28 lateral producers into the Schrader NB sand.

The L pad program included the L-47 lateral producer and L-50 lateral injector, both targeting the lower lobe of the Schrader OA sand. The K-44 producer targeting the Kuparuk C/B sands and the C-15A sidetrack producer targeted the Sag River formation.

For the development year beginning July 2017, Hilcorp plans to drill as many as 18 wells. The program would include wells at four pads and at all three formations at the unit. The company is also planning as many as 16 workover projects on existing wells.

According to its plan, Hilcorp will drill as many as 10 wells at F pad (four producers and five injectors into the Schrader Bluff OA sands and one Sag River producer), five wells at L pad (two producers and two injectors into the Schrader Bluff N sands and one Sag River producer), two wells at E pad (one producer and one injector into the Schrader Bluff formation) and one well at C pad (an injector into the Kuparuk formation).

Earlier this year, the company completed its first season of construction activity on the new 44-well Moose Pad, which would target Kuparuk and Schrader Bluff oil in the western end of the unit. Work will continue this winter with a road, pad and facilities.

The company expects to begin drilling activities starting next year, with first oil scheduled for late 2018. A full development program, with as many as 70 wells, could produce between 30 million and 50 million barrels, according to the company. The company expects peak production between 12,000 and 18,000 barrels per day.

The company will develop the Moose pad using the new, custom-built Innovation rig, which is already operating at the unit. The company is touting the rig as the lightest modular rig on the North Slope. The rig's ability to drill closely spaced wells will allow it to operate at the Endicott field and the Northstar unit, in addition to Milne Point.

Hilcorp is also planning an expansion at E pad, allowing for an additional eight wells.

"On the North Slope we are particularly bullish on the opportunities at Milne Point, where we believe a significant resource still remains to be recovered, from light oil trapped in deep reservoir rocks to heavy oil in the shallower Schrader Bluff and Ugnu formations," Hilcorp Alaska Senior Vice President David Wilkins said in May 2017. "We see plenty of reasons for investment and hundreds of wells yet to be drilled."

The Milne Point unit produced 7.1 million barrels in 2014, 6.8 million barrels in 2015, 7.2 million barrels in 2016 and 3.5 million barrels through the end of June 2017, according to the AOGCC. Cumulative production at June 2017 was 339.5 million barrels.

Duck Island (Endicott)

Having completed some preliminary workover activities at the Duck Island unit in recent years, Hilcorp is now transitioning into a major re-development program at the unit.

The company is planning a seven-well development program at the Duck Island unit in the year starting July 1. The program would include at least one new well and as many as six sidetracks, according to the most recent plan of development. Additional candidates for sidetracking will likely come from currently shut-in wells, according to the company.

In early August 2017, the Alaska Oil and Gas Conservation Commission issued a permit for Hilcorp to drill the Duck Island Unit SDI 3-23A well into the Endicott pool. The well would be the first at the unit since BP Exploration (Alaska) Inc. drilled the Duck Island Unit SDI 4-04A/T30 production well in 2009 and the first well with Hilcorp as operator.

Hilcorp is also planning at least two workover projects in the coming year.

In the year ending July 2017, Hilcorp undertook a major workover program at Duck Island. The company completed at least 12 workover projects in 2016, expected to complete another 10 project this year through July 1 and had three other projects underway that would last into the second half of 2017, according to its development plan.

The unit produced 2.7 million barrels in 2014, 2.5 million barrels in 2015, 2.5 million barrels in 2016 and 1.3 million barrels this year through the end of June, according to the AOGCC. Cumulative production was 485.4 million barrels through June 2017.

Northstar

Hilcorp has yet to drill any wells at the Northstar unit, focusing instead on workover projects at existing wells and on maintenance activities at facilities and infrastructure.

For the year ending July 2017, the company conducted seven workover projects at the unit — five at the Northstar participating area and two at the Hooligan participating area.

The company also completed some facility upgrades during the year.

For the coming year, running through July 2018, the company is planning three workovers projects at Northstar — one at each of the unit's participating areas. The company is also planning some facility upgrades and some pipeline maintenance.

The last new wells drilled at the Northstar unit were in early 2009, when BP Exploration (Alaska) Inc. drilled the Northstar Unit NS-33A sidetrack as a producing well.

Northstar produced 3.2 million barrels in 2014, 2.2 million barrels in 2015, 2.0 million barrels in 2016 and 1.2 million barrels this year through the end of June 2017, according to the AOGCC. Cumulative production was 168.2 million barrels through June 2017.

Liberty

As part of their new partnership, Hilcorp and BP took another look at the Liberty field, which had been on hold after BP cancelled an earlier plan for developing the field.

Hilcorp submitted a revised development plan to the U.S. Bureau of Ocean Energy Management in late 2014 that called for developing the estimated 80 million to 150 million barrel oil field from an artificial gravel island and a buried subsea pipeline.

The federal agency released a draft Environmental Impact Statement on the project in mid-August 2017, organized a series of local public meetings starting in early October 2017 and launched a public comment period running through mid-November 2017.

"Not only have similar proposals of the Liberty project been vetted and approved before, but gravel-based energy facilities have a proven record of safe operations, with some in production for over a decade in the Beaufort Sea," Hilcorp's Senior Vice President for Alaska David Wilkins said. "We are eager to work with the communities across the North Slope and our partners throughout the state to develop a project that will greatly benefit Alaska and bring greater domestic energy security to the country."

In its development plan, Hilcorp proposed building the new 9.3-acre Liberty island about 7.3 miles southeast of the Endicott satellite drilling island, in about 19 feet of water.

The island would be able to support between five and eight production wells, four and six injection wells and as many as two disposal wells. Infrastructure and facilities on the island would support oil production rates of some 60,000 to 70,000 barrels per day.

The island would be connected to onshore facilities through a 12-inch oil pipeline housed inside of a 16-inch outer pipe. The pipeline would run subsea for approximately 5.6 miles and another 1.5 miles overland until it reached a connection with the Badami pipeline.

Construction would occur in the second and third years of development. Drilling would begin in the second year of development and continue through the fourth. Oil production would begin by the end of the third year or the beginning of the fourth year of development, with an estimated life of approximately 20 years, according to Hilcorp.

The draft EIS included consideration of alternative locations for the gravel island and a plan to site facilities on Endicott Island rather than on Liberty Island, but it dismissed a proposal to access the target through ultra-extended reach drilling as technically infeasible.●

Contact Eric Lidji at ericlidji@mac.com

Barrow gas fields remain steady

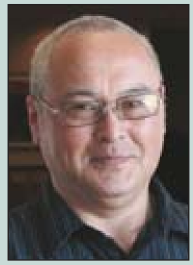
South Barrow, East Barrow and Walakpa fields give the city of Utqiagvik a unique advantage

By ERIC LIDJI
For Petroleum News

Residents of the northernmost city in America recently voted to rename their city Utqiagvik. But, for now, their local energy source is still called the Barrow gas fields.

Contractors working for the federal government discovered the South Barrow, East Barrow and Walakpa fields on separate expeditions into the northwest corner of the North Slope Borough between the late 1940s and the 1980s. The three gas fields powered the city of Utqiagvik for decades before noticeable declines prompted municipal leaders to push for a re-development campaign. A pair of voter-approved bonds allowed the city to launch a $92 million rejuvenation program in 2011. The city commissioned the Savik 1 and 2 wells at East Barrow and the Walakpa 11, 12, and 13 wells at Walakpa. By improving deliverability, Utqiagvik can now use gas for its energy needs even during cold snaps or maintenance activities, instead of switching to diesel as an alternative.

NAME OF COMPANY:
North Slope Borough
COMPANY HEADQUARTERS:
P.O. Box 69 Barrow, Alaska 99723
TELEPHONE:
907-852-2611
TOP ALASKA EXECUTIVE:
Mayor Harry K. Brower, Jr.


HARRY BROWER JR.

South Barrow

The U.S. Navy discovered the South Barrow field with the 2,505-foot South Barrow No. 2 well in 1948, during its initial wave of National Petroleum Reserve-Alaska exploration.

Production began the following year. Drilling continued for decades, with 13 new wells drilled and one existing well deepened by 1987, according to the Alaska Oil and Gas Conservation Commission. Production peaked at some 3.5 million cubic feet per day in November 1981. The field is now used primarily to meet peak demand during the winter.

According to the AOGCC, the South Barrow field had produced more than 23.7 billion cubic feet of gas at the start of 2014, and cumulative production was unchanged by the end of June 2016. Geologists originally expected the field to produce some 32 bcf.

East Barrow

The U.S. Geological Survey discovered the East Barrow field with the South Barrow No. 12 well in 1974, during the second wave of oil and gas exploration in the NPR-A.

Production began in December 1981. Drilling continued through 1990, with eight wells total. East Barrow production peaked at some 2.75 million cubic feet per day in 1984.

According to the AOGCC, cumulative production at East Barrow was 8.9 bcf at the start of 2015, 9.1 bcf at the start of 2016 and 9.2 bcf by the start of 2017, suggesting a relatively steady rate of production with occasional fluctuations caused by demand.

The current cumulative total is nearly 50 percent above the originally estimated 6.2 bcf in place for the East Barrow field. The city of Utqiagvik attributes the productivity to methane hydrates — molecules of gas trapped in cages of ice and released through pressure changes. Drops in pressure occur naturally during the aging process of a field.

Walakpa

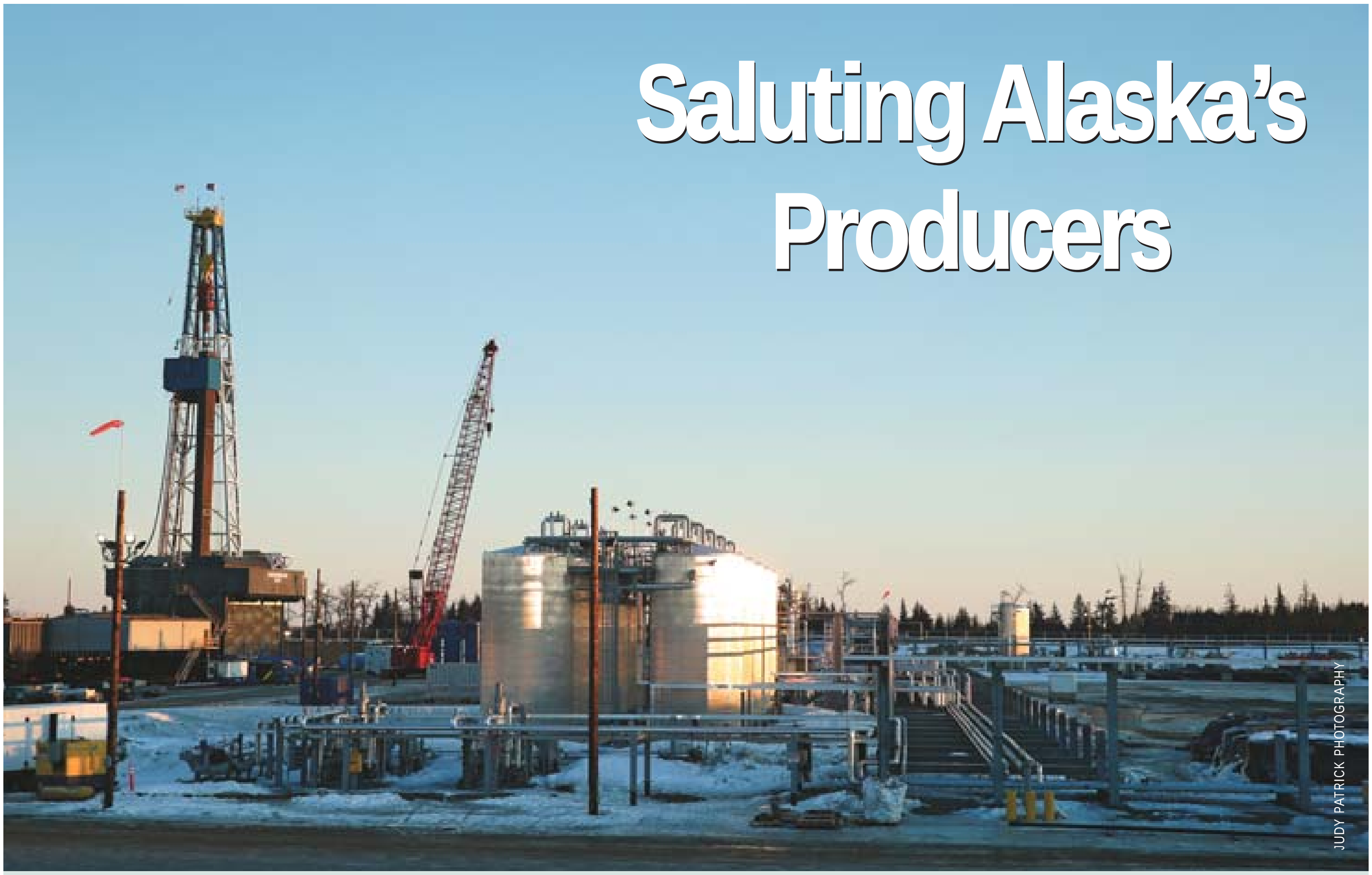
Working under a Navy contract, Husky Oil discovered the Walakpa field with the 3,666-foot Walakpa No. 1 well in the 1980s. Production began in the early 1990s. The field has peaked above 5 million cubic feet per day numerous times, including in early 2013.

Today, Walakpa produces the majority of the gas delivered to Utqiagvik.

According to the AOGCC, cumulative production at Walakpa was approximately 26.9 bcf by the start of 2015, approximately 28.3 bcf by the start of 2016 and approximately 29.7 bcf by the start of 2017, suggesting steady annual production rates in recent years.

The South Barrow and East Barrow reservoirs have a stratigraphic setting similar to the Alpine oil field. Walakpa is in the Pebble Shale unit, a major North Slope source rock. ●

Contact Eric Lidji at ericlidji@mac.com



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