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One challenge, many responses

A period of low oil prices is forcing Alaska producers to strategize

By ERIC LIDJI
For Petroleum News

The persistence of low oil prices over the past two years has been a challenge for all Alaska oil and natural gas producers and by extension for their suppliers and contractors.

But as The Producers shows, each producer responded to the challenge differently.

Caelus and Eni both suspended their development programs in the short-term while keeping an eye on longer-term projects to pursue when prices improve. BP dramatically slowed its development program after having ramped up considerably in recent years.

Hilcorp eased its furious pace of activity at its Cook Inlet properties while increasing investment at its new North Slope properties, specifically Milne Point. ConocoPhillips took a similar approach — slowing the Drill Site 1H project and reducing some infill drilling while continuing work at Drill Site 2S, expanding CD-5 and sanctioning GMT-1.

BlueCrest and Furie both brought new offshore Cook Inlet developments online over the past year but also proceeded cautiously. BlueCrest postponed a proposed gas development at Cosmopolitan for the time being while Furie balanced its desire to expand Kitchen Lights production with the realities of the local marketplace. Both projects reveal the peculiarities of the Cook Inlet natural gas market, which has stepped back from the brink of a few years ago but remains challenging for smaller producers.

ExxonMobil brought the Point Thomson unit into production, but uncertainty about the future of the project is overshadowing the major milestone in North Slope history.

Brooks Range Petroleum resumed development work at the Mustang field on the North Slope. While financing remains challenging, the company expects a late 2017 startup.

Glacier emerged from bankruptcy protection this year and is already proving to be much leaner than its predecessor Miller Energy, having eliminated some longer-term exploration projects from its portfolio to focus on development. Aurora appeared eager to explore and develop before starting the bankruptcy process this year. Whether the company will retain that eagerness afterward, or change its approach, remains to be seen.

AIX Energy and the North Slope Borough carried on this year much as they carried on last year, showing that some projects are immune to aspects of the global economy. ●

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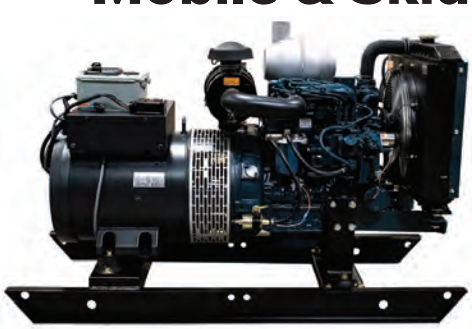

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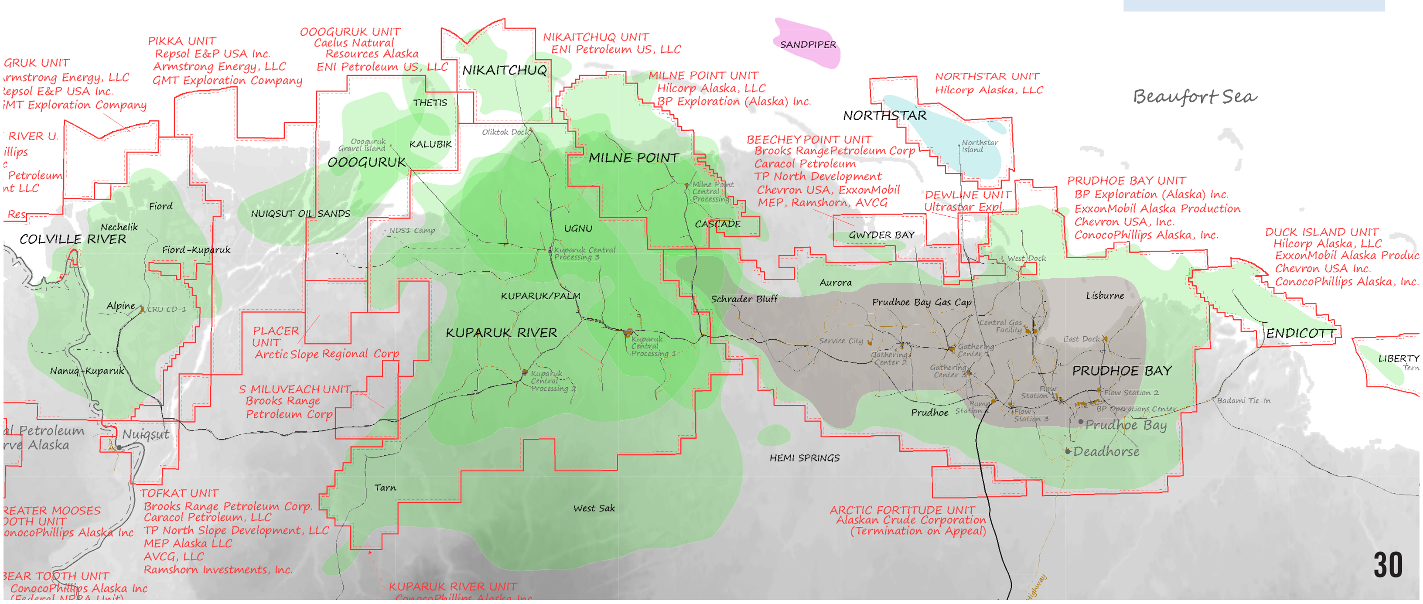
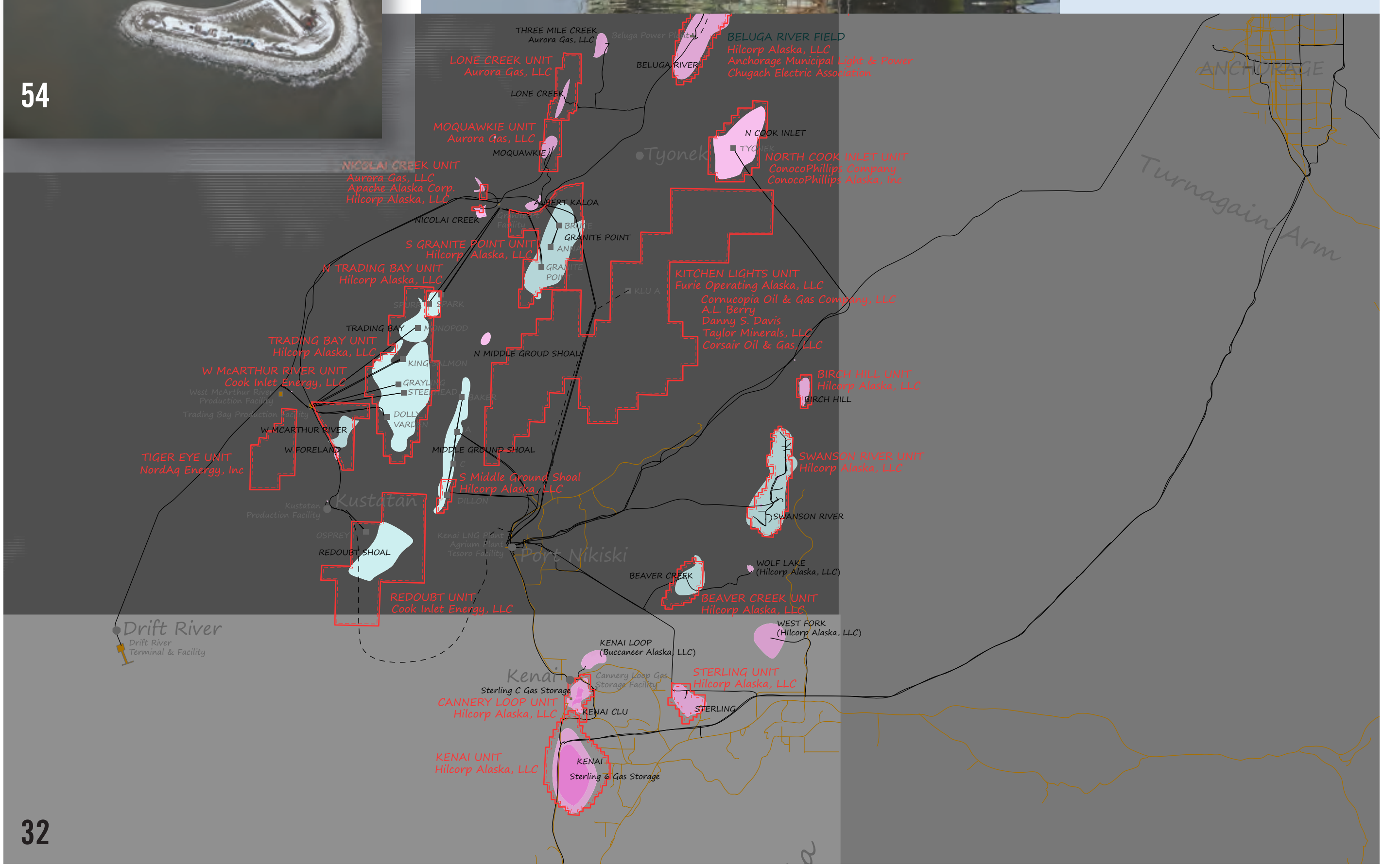


Welcome

Ad Index

Maps



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On the cover: Jessika Gonzalez, permitting coordinator for ConocoPhillips Alaska, stands on the CD5 drill site with Doyon Rig 19 in the background.

Photo courtesy Judy Patrick

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AIX Energy remains small but steady at Kenai Loop

Onshore gas field will require upgrades in the near future to maintain production

By ERIC LIDJI
For Petroleum News

AIX Energy LLC is steadier, quieter and more cautious than its Kenai Loop predecessor.

The small Texas-based independent is anticipating a range of development projects over the next year to improve the operation and production profile of the onshore Cook Inlet natural gas field. But those plans are unlikely to include drilling new wells or sidetracks.

After acquiring the debt of Australian independent Buccaneer Energy Ltd. in April 2014, AIX Energy acquired most of the company's Alaska assets at an October 2014 auction.

Prior to the acquisition, Buccaneer was actively pursuing drilling opportunities at the small field near the city of Kenai with limited success. Since the acquisition, AIX Energy has limited its activities to maintenance, upgrades and repairs of existing infrastructure.

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. The field was the only producing asset the company owned in Alaska, nestled among an ambitious portfolio of exploration projects that pushed the company into financial straits and then bankruptcy.

Although Buccaneer regularly touted drilling opportunities it hoped to pursue, AIX Energy is more skeptical. A third party evaluation by geophysicist Scott Daniels in 2015 found no drilling opportunities on the existing development lease, according to AIX.

Of the four wells, only two are currently producing. A February 2015 deliverability test determined that the two producing wells could produce 15.8 million cubic feet per day, which is sufficient to meet current contractual commitments, according to the company.

Kenai Loop production has been stable in recent years. At the start of 2014, the field had produced some 4.8 billion cubic feet of natural gas, according to the Alaska Oil and Gas Conservation Commission. By the start of 2015, cumulative production had increased approximately 3.3 bcf to a total of more than 8.1 bcf. By the start of this year, total production had increased approximately 3.6 bcf to approximately 11.7 bcf.

In the first half of 2016, Kenai Loop produced some 1.7 bcf. If the field produces at a similar rate in the second half, it would be a slight decline from 2015.

Restoring wells

AIX Energy spent much of 2015, its first year as field operator, handling administrative and regulatory matters relating to the acquisition, as well as some operational matters such as removing the dry solids from the Buccaneer-operated West Eagle No. 1 exploration well that the former operator had been storing at the Kenai Loop drilling pad.

Toward the end of 2015, Chugach Electric Association asked regulators to extend its existing natural gas supply agreement with AIX Energy by eight years, to March 31, 2024, with the possibility of an additional extension through March 31, 2029.

Over the next year, according to a plan of development filed in early May 2016, AIX Energy plans to install gas compression in order to meet contractual requirements and maximize reserve recovery, and is considering plans to re-perforate an existing well and return a suspended well to production to improve deliverability at the field.

The company believes the gas compression will be necessary within the next year and is currently considering whether to lease or buy a system and whether to use gas-powered or electric power compression. As part of those evaluations, the company is also considering whether or not to return the existing Kenai Loop No. 1-4 well to production "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 Kenai Loop No. 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 the Kenai Loop No. 1-1 well. Kenai Loop No. 1-4 currently monitors reservoir pressure.

Along similar lines, AIX Energy is considering whether to re-perforate the existing Kenai Loop No. 1-3 well to improve deliverability and the company believes there is a "high probability" it will undertake the project sometime during the next 12 to 18 months.

AIX Energy is also evaluating alternatives for disposing of water produced during drilling operations. According to the company, water disposal is currently the second highest lease operating expense at the field, after personnel. In 2015, the company made a cost-benefit analysis of installing an onsite evaporator. Although the project seemed to promise some "modest benefits," the company is now considering third-party services.

Contract extension

Although AIX Energy generally remains quiet, the company occasionally states its opinions in regulatory hearings, both for

continued on next page

AIX ENERGY *continued from page 9*

contracts and also for wider Cook Inlet issues.

Toward the end of 2015, Chugach Electric Association asked regulators to extend its existing natural gas supply agreement with AIX Energy by eight years, to March 31, 2024, with the possibility of an additional extension through March 31, 2029.

The contract would allow Chugach to purchase as much as 3 bcf per year from AIX Energy but would not require either side to commit to buying or selling gas.

Instead, the two companies would negotiate each individual gas transaction on a case-by-case basis with a price cap rising by approximately 2 percent each year. The maximum price would increase from ranging from $6.13 per thousand cubic feet in 2016-17, to $7.17 per mcf in 2022-23, to $8.07 per mcf in 2028-29.

AIX Energy has also negotiated supply contracts with Enstar Natural Gas Co.

In addition to its supply contracts, AIX Energy publically advocated for an extension of the federal export license for the Kenai liquefied natural gas export terminal.

"In addition to operating producing gas wells, AIX holds exploration leases in the Cook Inlet area. Future development and exploration decisions are dependent upon the assurance of market demand for AIX's future natural gas production. Accordingly, AIX stands in support of the continued export of LNG from the Cook Inlet Basin," AIX Energy LLC Manager Fred Tresca wrote in a June 25, 2015, letter to federal officials.

And the company was one of many players in the region to intervene in a rate case for the Kenai Beluga Pipeline. The regional pipeline was requesting a substantial tariff increase.

Over the past two years, AIX Energy has significantly increased its land holdings in Alaska. The company held 1,049 acres of state leases as of April 2015 and approximately 8,882 acres as of May 2016. The company also holds Alaska Mental Health Trust leases.

AIX Energy acquired two leases — ADL 393033 and ADL 393035 — in the vicinity of the Kenai Loop field during a May 2015 lease sale. In January 2016, the company acquired 100 percent working interest and 80.25 percent royalty interest in two Cook Inlet leases from Buccaneer. One lease — ADL 391609 — is west of the existing Nicolai Creek unit and was previously known as the West Nicolai Creek prospect. The other lease — ADL 391611 — is an offshore lease just west of the existing North Cook Inlet unit. ●

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Aurora bankruptcy delays development

Independent had proposed a major development campaign before reorganization process began

By ERIC LIDJI
For Petroleum News

Aurora Gas LLC entered bankruptcy protection earlier this year after more than 15 years of operation. The small Alaska independent blamed its financial problems on a combination of declining natural gas production at its Cook Inlet properties and a recent workover project that cost more than $1 million but failed to improve production rates.

Those problems followed a recent change in ownership. 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. Later, Kaiser-Francis Oil Co.-affiliate Aurora-KF LLC owned a 95 percent interest in Aurora Gas, with Aurora Power Resources owning 4 percent and Orion Resources Inc. owning 1 percent, according to state records. In August 2015, independent Rieck Oil Inc. acquired Aurora Gas outright.

ED JONES

Aurora filed for bankruptcy protection after three creditors — Aurora Well Service LLC, Shirleyville Enterprises LLC and Tanks-A-Lot Inc. — filed an involuntary petition with the United States Bankruptcy Court for the District of Alaska in May 2016. According to court records, as of June 1, Aurora owed its 20 largest creditors nearly $1.5 million.

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The bankruptcy proceedings were still underway as The Producers went to print. When Rieck Oil acquired the company, Aurora Gas was operating five fields on the west side of Cook Inlet: Nicolai Creek, Lone Creek, Moquawkie, Kaloa and Three Mile Creek.

All five of those fields have seen minimal development work over the past three years and in some cases much longer. In a public presentation released in February 2016, Rieck Oil outlined a major exploration and development program through the end of 2017. The bankruptcy process has postponed any development, but the presentation provides a sense of the investment opportunities available within the existing Aurora Gas portfolio.

At the Nicolai Creek unit, Aurora would drill the NCU No.

12 extension well and the NCU No. 15 step-out well from the existing NCU No. 9 well. At the Moquawkie unit, the company would drill two extension wells into the West Moquawkie prospect.

The proposed program also called for acquiring a package of existing Apache Alaska Corp. 3-D seismic over the region to learn more about exploration leads around the Nicolai Creek unit, the Kaloa field and other areas throughout the leasehold. The company also wanted to follow exploration leads in other sections of its leasehold and was looking for a partner to share the expense of pursuing those opportunities.

In addition to this exploration and development drilling, Rieck Oil was proposing a considerable maintenance campaign at its existing wells. The company wanted to work over as many as eight existing wells spread across all five of its producing fields.

Five fields

With the bankruptcy proceedings, the future of those plans remains uncertain.

Aurora drilled no new wells at the Nicolai Creek unit in 2014, 2015 or the first nine months of 2016, although the company regularly proposed drilling in its plans of development. By the start of 2014, the Nicolai Creek unit had produced 8.14 billion cubic feet, according to figures from the Alaska Oil and Gas Conservation Commission. The unit produced 453.2 million cubic feet that year and 424.4 million cubic feet in 2015 for a total of 9.02 bcf by the start of this year. The unit produced 180 million cubic feet in the first six months of 2016, which suggests a decline from 2015 rates.

Aurora drilled no wells at Lone Creek in 2014, 2015 or the first nine months of 2016. By the start of 2014, the Lone Creek unit had produced 10 billion cubic feet. The unit produced 477.2 million cubic feet that year and 369.3 million cubic feet in 2015 for a total of 10.9 bcf by the start of this year. The unit produced 109.2 million cubic feet in the first six months of 2016, which suggests a decline from 2015 rates.

Aurora drilled no wells at Moquawkie in 2014, 2015 or the first nine months of 2016. By the start of 2014, the Moquawkie unit had produced 4.92 billion cubic feet. The unit produced 76.7 million cubic feet that year and 36.6 million cubic feet in 2015 for a total of 5.03 bcf by the start of this year. The unit produced 19.5 million cubic feet in the first six months of 2016, which suggests an increase from 2015 rates.

Aurora drilled no wells at Albert Kaloa in 2014, 2015 or the first nine months of 2016. By the start of 2014, the Kaloa field had produced 3.59 billion cubic feet. The field produced 6.9 million cubic feet that year and 3.5 million cubic feet in 2015 for a total of 3.6 bcf by the start of this year. The field produced just 946,000 cubic feet in the first six months of 2016, which suggests a decline from 2015 production rates.

Aurora drilled no wells at Three Mile Creek in 2014, 2015 or the first nine months of 2016. By the start of 2014, the field had produced 2.39 billion cubic feet. The unit produced 65.1 million cubic feet that year and 77.1 million cubic feet in 2015 for a total of 2.53 bcf by the start of this year. The unit produced 34.3 million cubic feet in the first six months of 2016, which suggests a decline from 2015 production rates. ●

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BlueCrest brings Cosmopolitan online

After five operators and nearly half a century, BlueCrest makes it work

By ERIC LIDJI
For Petroleum News

The Cosmopolitan unit needed the right company at the right time.

Earlier this year, BlueCrest Energy Operating LLC started producing oil at the Cook Inlet field after five previous operators over 49 years were unable to make the project work.

J. BENJAMIN JOHNSON

Its predecessors included integrated oil companies, large independents and small independents. Oil prices were high, low and in between over that half a century.

BlueCrest succeeded through a combination of previous activities by former operators, a limited scope of work for the time being and external assistance from public agencies.

From its inception, the small privately held company based out of Fort Worth was focused primarily on Cosmopolitan, which reduced internal competition for resources.

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BlueCrest was also helped in its effort by two state programs. The Alaska Industrial Development and Export Authority partly financed a jack-up rig used to drill an initial exploration well at the offshore unit, and the Alaska Department of Revenue provided tax credits that offset some of that exploration activity, reducing the cost of the project.

Having brought the Cosmopolitan unit into production from an existing well, BlueCrest is now focusing on development work. By summer, the company had brought a custom-built land-based drilling rig to the Kenai Peninsula and was starting to permit extended reach development wells from a 38-acre onshore drill site north of Anchor Point.

BlueCrest plans to drill as many as five wells and laterals in early 2017. In August 2016, the company received an Alaska Oil and Gas Conservation Commission drilling permit for the H-16 well. The company expects to request drilling permits for the H-14, H-14L, H-12 and H-12L wells and associated laterals early next year, according to the plan of development. The drilling program will begin as soon as BlueCrest finishes building the BlueCrest Rig No. 1. The work is occurring on site and is expected to be complete by the end of the year. The company is also permitting a disposal well to be drilled after the development program is finished. A second disposal well is likely at some undetermined point in the future.

The production facilities at Cosmopolitan can accommodate 20 wells and process as much as 10,000 barrels per day. Although the existing well was producing only 250 bpd by early July, the company believes it will reach capacity in time. The initial well, according to BlueCrest, is in a less productive section of the prospect. The large grounds around the facility can accommodate expansion, if production warrants.

As BlueCrest drills horizontal oil wells, the company is also planning ahead to the possibility of developing gas from a separate reservoir above the oil accumulation. With the demand for gas in Cook Inlet currently satisfied, and tax credits curtailed, BlueCrest recently suspended those plans and cancelled a federal permitting application.

Before those tax credits were curtailed, BlueCrest President J. Benjamin Johnson said, "The main benefit of the tax credits to us is that they would allow us to continue developing Cosmopolitan at a lower oil price, at about $10 a barrel lower price, in fact."

The unusual life of Cosmopolitan left a short production history before BlueCrest brought the field into production. The field had produced 33,504 barrels of oil by the start of 2016, and produced 20,931 barrels through the first six months of the year for cumulative production of 54,435 barrels by the end of June 2016, according to the AOGCC.

Five predecessors

The story of Cosmopolitan offers insights into the history of the Cook Inlet market.

Using a jack-up rig, Pennzoil discovered the prospect in 1967 with the 12,112-foot vertical Starichkof State No. 1 discovery well and the down-dip Starichkof State Unit No. 1 well. Although the wells encountered oil, the results of those wells were uninspiring.

In addition to geologic risk, the southern Kenai Peninsula was beyond the terminus of the Cook Inlet distribution system at the time, which further challenged the project.

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 for $7 billion.

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 Hansen No. 1 exploration well from 2001 confirmed the presence of oil in the Starichkof sands and also discovered

continued on page 17


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BLUECREST *continued from page 15*

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. The sidetrack targeted the Starichkof and Hemlock reservoirs. A subsequent flow test produced 1,000 barrels of oil per day and 14,851 cumulative barrels.

Even though the prospect remained beyond the existing distribution grid, one royalty owner made the case for trucking oil north to existing refineries. But the state disagreed, saying that ConocoPhillips needed further delineation work to prove up the prospect.

By 2005, ConocoPhillips and Pioneer Natural Resources were working together on a range of exploration projects across the North Slope. Cosmopolitan provided an opportunity to extend the partnership to Cook Inlet. A joint 3-D seismic program "provided a clear view of the perimeter flanks of an anticlinal structure, but the crestal view of the structure was obscured by a gas cloud, rendering a conclusive description of the reservoir structure unobtainable at the time," according to filings from BlueCrest.

After the companies dissolved their partnership, Pioneer acquired ConocoPhillips' interest in Cosmopolitan 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.

Between early 2004 and late 2007, the average spot price of Alaska North Slope crude oil increased from $33.10 to $88.63 per barrel and would eventually peak above $130 per barrel in mid-2008, when Pioneer brought the Oooguruk unit online on the North Slope.

COURTESY BLUE CREST

When global oil prices collapsed in late 2008, Pioneer Natural Resources maintained its operations at Oooguruk but slowed its investment at Cosmopolitan. The company fracture stimulated an interval at Hansen No. 1A-L1 in 2010 and an extended flow-test produced 250 bpd. Under a pilot program to truck Cosmopolitan oil to the Tesoro refinery to the north, Pioneer produced more than 33,000 barrels from the field.

As the nearby North Fork unit was nearing production in late 2010 and early 2011, the associated infrastructure improved the economics of producing natural gas from Cosmopolitan. Pioneer continued to focus on oil, even going so far as to proposing a full-scale development program. But in early 2011, the company soured on the project, terminated the unit and relinquished all its leases except

continued on page 21

BP promises cuts to Prudhoe Bay program

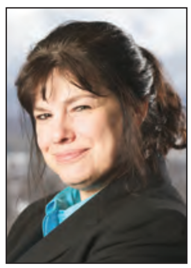
Low oil prices halt a major increase in development activities

By ERIC LIDJI
For Petroleum News

Of all the companies that maintained some drilling program in Alaska this year, BP Exploration (Alaska) Inc. had the harshest response to the current economic climate.

A number of operators suspended drilling programs entirely for the short term, hoping oil prices would recover. Others scaled back operations. And still others made field-by-field determinations about where to advance and where to retreat while prices remain low.

After several years of increased activity at the Prudhoe Bay unit, BP made several big cuts over the course of 2016. The company announced a 13 percent reduction in workforce in January and increased the cuts to 17 percent in March. Over roughly the same period of time, the company idled four of the six rigs it had operating at the unit.



JANET WEISS

Those decisions set the table for the three plans of development the company filed over the course of 2016 to describe its recent activities and upcoming plans for the unit: for the Initial Participating Areas, the Greater Point McIntyre Area and the Western Satellites.

All three plans showed the results of the increased development program in 2015 — some more than others — and all three suggested fewer activities across the unit this year.

According to the Alaska Oil and Gas Conservation Commission, BP drilled 52 wells at Prudhoe Bay in 2014 and 75 in 2016.

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The company had drilled at least 26 in the first six months of 2016, which suggests a drilling program more in line with 2014 levels.

How the reductions will impact production remains to be seen. By the start of 2014, the entire Prudhoe Bay unit had produced 12.41 billion barrels of oil. The unit produced 90.2 million barrels that year and 88.4 million barrels in 2015 for a total of 12.59 billion barrels by the start of this year. In the first six months of 2016, the Prudhoe Bay unit produced 45.1 million barrels, suggesting growth as a result of the 2015 program.

Initial Participating Areas

At the Initial Participating Areas, the largest of the three administrative areas at Prudhoe Bay and the first to report each year, BP told the state it expected to reduce drilling activities to 1.6 rig years in 2016, down from 3.8 rig years in 2015. Seen another way, the company expected to drill some 31 wells or side-

continued on page 21

BP *continued from page 19*

tracks this year, compared to 60 in 2015.

BP predicted a slight decline in production to a range of 157,000-196,000 barrels of crude oil and condensate per day in 2016. The company produced some 196,400 bpd in 2015, which fell at the high end of the range of 157,000-200,000 bpd BP had forecast. The company also predicted natural gas liquids production between 36,000 and 45,000 bpd in 2016. That might actually yield an increase over the 38,000 bpd the company produced in 2015, which was also at the high end of a forecast of 31,000-39,000 bpd.

BP had forecast harsher declines — 10 to 30 percent for crude oil and condensate and 2.6 to 24 percent for natural gas liquids — in its original filing, before revising its figures.

The drilling programs in recent years have been spread in clusters across the geographic expanse of the unit. The 2015 program included a cluster into the Sag River formation in the north-central section of the unit, concentrated on the Northwest Fault Block. The cluster included five wells from F-pad, four wells from R-pad, one well from S-pad and an associated well from Drill Site 03. All but one was a sidetrack of an existing well.

The program for this year is also spread across the unit, with a cluster of eight wells planned for Drill Site 03, Drill Site 09 and Drill Site 16 in the southeast of the unit.

The cuts planned for this year include both drilling and maintenance.

BP told the state it intended to drill eight rotary wells this year, down from 19 in 2015, and 24 coiled tubing wells, down from 41 in 2015. Of those wells, only two would be new, or “grassroots” wells, down from eight last year. (The rest would be sidetracks.)

The plan calls for even steeper declines in certain well workover activities, which involve repairing old wells to improve operations. The company is planning rig workover operations at four wells this year, down from 27 last year, although some of that decline can be attributed to the increasing success of non-rig workover operations at the field.

The Initial Participating Areas plan of development yielded another disturbing development. The state required BP to provide information about marketing plans for future natural gas production at the Prudhoe Bay. The company declined.

continued on page 22

BLUECREST *continued from page 17*

the two that were held by wells, which it sold to BlueCrest and its operating partner Buccaneer Energy Ltd. Pioneer soon left Alaska entirely to focus on unconventional oil opportunities in the Lower 48.

Apache Alaska Corp. bought the remaining leases but later sold them to the Buccaneer and BlueCrest partnership when it, like Pioneer, decided to back away from Alaska. The company had faced disappointing well results at other fields and long regulatory delays.

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. ●

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BP *continued from page 21*

A debate remained unresolved throughout much of the year, prompting concerns of an ongoing legal battle. The state and the company reached an agreement in late September.

Greater Point McIntyre Area

The fields in the Greater Point McIntyre Area have been in a holding pattern in recent years and should remain that way this year, according to a recent development plan.

Future activity in the region depends largely on the results of the North Prudhoe seismic survey. BP completed the offshore portion of the survey in December 2014 and the onshore portion in April 2015 and expects processing to take at least "one to two years."

The Greater Point McIntyre Area includes six fields. The Point McIntyre and Lisburne fields are the largest, followed by Raven, Niakuk, North Prudhoe Bay and West Beach.

At Lisburne, BP drilled three wells — L1-23, L3-03 and L3-10 — and performed 31 rate-adding non-rig workover projects on 26 existing wells at the field. The company expects to drill two additional wells — L1-13 and L5-12A — during the upcoming period and is considering several additional drilling locations pending the result of those wells.

The Lisburne field produced some 5,800 barrels per day of crude oil, condensate and natural gas liquids in the year ending March 31, 2016 — up from 4,800 bpd during the same period in 2015 and down from 6,400 bpd during the same period in 2014.

Lisburne produced some 117.3 million cubic feet of gas per day during the reporting period — up from 91.4 mmcfpd in 2015 and down from 124.1 mmcfpd in 2015. Most of the gas produced at Greater Point McIntyre is re-injected to improve oil production.

One strategy BP is using to reduce the gas-to-oil ratio and increase oil production involves intermittent production cycles, rather than continuous production.

Those rates yielded a gas-to-oil ratio (standard cubic feet divided by stock tank barrels of oil) of 20,071 in 2016, 19,224 in 2015 and 19,269 in 2014. The high and increasing ratio impacts oil production, as ambient temperatures in the region influence the efficiency rates of compressors that determine oil off-take rates, according to the company.

One strategy BP is using to reduce the gas-to-oil ratio and increase oil production involves intermittent production cycles, rather than continuous production. Certain wells are produced for several days at a time followed by days or even weeks of being shut-in.

Activity at the other fields in the Greater Point McIntyre Area depends partially on the results of the seismic survey. Point McIntyre produced 15,410 barrels of liquids per day in the year ending March 31, 2016, down from 16,370 bpd in the 2015 period and 18,520 bpd in the 2014 period. The field produced 62.5 billion cubic feet of gas during the 2016 period, down from 69.6 bcf in the 2015 period and 62.4 bcf during the 2014 period.

The Niakuk field produced 1,110 barrels of liquids per day during the 2016 period — up from 1,020 bpd during the 2015 period and down from 2,300 bpd during the 2014 period.

Niakuk produced 800 million cubic feet of gas during the 2016 period — up from 300 mmcf during the 2015 period and down from 1 bcf during the 2014 period.

While BP reported no drilling activity at either field in the 2016 period, the company described an “active” non-rig workover program at both fields. The company performed one rigged project at the Point McIntyre field to repair a casing leak at the P1-14 well and restore the well to normal injection in March 2016, and seven projects at Niakuk.

The Raven field produced 130 barrels of liquids per day during the 2016 period — down from 170 bpd during the 2015 period and 310 bpd during the 2014 period. The field produced 730 million cubic feet of gas during the 2016 period — up from 590 mmcf during the 2015 period and up from 700 mmcf during the 2014 period.

The North Prudhoe Bay field and the West Beach field have been shut-in since February 2000 and January 2001, respectively. Restarting North Prudhoe Bay production would require repairs to its sole production well and overcoming geological challenges in the Ivishak and Sag River formations, according to BP. Restarting production at West Beach would require an internal pipeline integrity inspection, according to BP. In both cases, the seismic survey could potentially hasten development work by reducing technical risks.

Western Satellites

Unlike the production declines at the Initial Participating Areas and the Greater Point McIntyre Area, BP reported increased oil production at four of the five Western Satellites — Aurora, Borealis, Midnight Sun, Orion and Polaris — at the Prudhoe Bay unit.

The increases came from a combination of drilling activity at a few fields and maintenance activities at the other fields. Whether those activities can continue at a time when the company is reducing both its workforce and its drilling plans in response to depressed oil prices remains to be seen. The longer-term projects required for maintaining growth at the western satellites appear to be on hold for another year.

As has been the case for years, the plans offer little progress on several big projects, such as construction of a pro-

Unlike the production declines at the Initial Participating Areas and the Greater Point McIntyre Area, BP reported increased oil production at four of the five Western Satellites — Aurora, Borealis, Midnight Sun, Orion and Polaris — at the Prudhoe Bay unit.

posed I pad or an expansion of the existing S pad and M pad, all of which are on hold until a sand control trial can be completed at Z pad. Additionally, BP is continuing to search for ways to improve the sand handling capacity of Gathering Center 2, which was created to handle lighter oil than is currently being produced.

Aurora produced 6,303 barrels of oil per day between July 2015 and June 2016, up from 4,305 bpd during the 2014-15 cycle and 4,655 bpd during the 2013-14 cycle.

In the final months of 2015, BP drilled the S-42A producer to replace the abandoned S-108 producer and the S-44A producer north of the S-101 injector. This year, BP undertook two big development projects. In the first quarter, the company hydraulically fractured the S-135 well. The well produced 3,587 bpd after the operation, compared to 836 bpd in the most recent test before the operation, according to the company. In the second quarter, the company drilled the S-112L1 lateral to support S-42A. The lateral failed to reach its target. BP converted the well and a portion of the lateral to injection.

BP provided no specific development program for the coming year, aside from mentioning plans to continue well work as needed and considering future drilling targets.

Borealis production fell during the year, although the rate of decline slowed from 2015.

The field produced 8,517 barrels of oil per day during the 2015-16 cycle, down from 8,768 bpd during the 2014-15 cycle and 9,932 bpd during the 2013-14 cycle, according to the company. The 2.8 percent decline in oil production between this year and last was far less than the 11.7 percent decline between last year and the year before.

Borealis is developed from three pads — L, V and Z.

BP focused its development work on L pad and Z pad this year. The company hydraulically fractured the L-123 injector and L-124 producer in late 2015 and early 2016. The L-123 well was returned to injection. The L-24 well produced an initial rate of 1,758 bpd after the operation, and “stabilized at a lower rate that was well in excess” of a rate of 83 bpd recorded before the operation. The company also brought the Z-114 injector into operation in early 2016 and repaired the Z-504A and Z504B wells.

BP suspended production and injection at V pad in June 2016 “due to piping over stress findings from an engineering study.” The company launched the study after noticing subsidence at the pad. While BP is currently modifying the piping and support system, and told the state it is expecting to resume operations by the end of the year, any activities undertaken in the coming months would only be a short-term solution combined with ongoing monitoring. The company expects a long-term solution to take until early 2018.

Aside from mentioning vague plans for well work and new drilling as needed, BP provided no details for drilling and

continued on page 24

BP *continued from page 23*

maintenance work at Borealis for the coming year.

Midnight Sun production rose over the year.

The field produced 1,134 barrels of oil per day during the 2015-16 cycle, up from 964 bpd during the 2014-15 cycle and 1,106 bpd during the 2013-14 cycle.

The only major activity at the field this year was repairs to the offline P1-122i injection well drilled in early 2015. The work restored the well to injection. The company said it was not planning any additional drilling work at Midnight Sun over the coming year.

Orion production rose during the year.

The field produced 4,747 barrels of oil per day during the 2015-16 cycle, up from 4,693 bpd in the 2014-15 cycle and down from 5,483 bpd in the 2013-s14 cycle.

While the company did not drill at the field over the past year, it conducted considerable maintenance activities, such as changing the waterflood regulation valves of 15 injection wells. The field also produces from V pad and experienced down time similar to Borealis.

Aside from mentioning vague plans for well work and new drilling as needed, BP provided no details for drilling and maintenance activities at Orion for the coming year.

In addition to I pad, BP is looking for ways to reduce downtime at viscous wells in the northwest portion of the field, near the proposed I pad. Over the past year, the company considered sidetracking the L-200 and L-205 producers. "In their current states, both wells have little to no remaining value. A plan to re-drill both multi-lateral producers as vertical wells with frac-pack completions is being evaluated," the company wrote. A similar evaluation is underway at the Borealis field, which lies beneath the Orion field.

Polaris production rose during the year.

The field produced 4,306 barrels of oil per day during the 2015-16 cycle, up from 3,890 bpd during the 2014-15 cycle and 4,080 bpd during the 2013-14 cycle.

As with Orion, BP did not drill at Polaris over the past year but performed considerable maintenance work such as changing waterflood regulation valves on eight injection wells.

The company listed no specific drilling plans for the coming year. ●

BRPC resumes work on Mustang project

Company expects to resolve technical delays in time for a late 2017 startup

By ERIC LIDJI
For Petroleum News

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Earlier this year, Brooks Range Petroleum Corp. said that it expected to begin oil production from the Mustang field at the Southern Miluveach unit in November 2017.

The operating subsidiary of a three-company joint venture had initially expected to bring the field online in April 2016 and later pushed the start date toward the end of 2016.


BART ARMFIELD

A comparison puts those delays in perspective. If the company hits its target date, the Mustang project will have taken almost seven years between the first exploration wells in early 2011 and commercial production in late 2017. How does that compare to the time span between the official discovery date and the start of commercial production at the three most recent North Slope fields to come online? Point Thomson took 39 years, Nikaitchuq took seven years and Oooguruk took 16 years. Even measuring Point Thomson and Oooguruk from more recent development campaigns yields a favorable comparison.

"We're off to a new start now," Brooks Range Petroleum Operations and Strategy Manager Jack Laasch told the Alaska Support Industry Alliance in May 2016. He was referring to both the resumption of development work and to new ownership.

JK E&P Group Pte. Ltd., Thyssen Petroleum North Slope Development LLC and MEP Alaska LLC acquired BRPC and a package of North Slope properties from Alaska Venture Capital Group and Ramshorn Investments Inc. for $450 million in mid-2014.

In return for using the Alaska Industrial Development and Export Authority as a financier for two major infrastructure projects at the Mustang project, the consortium handed over some working interest in the leases to a pair of public-private joint ventures. After all the dust had settled from those deals, BRPC was operating the Southern Miluveach unit on a behalf of seven working interest owners: JK E&P subsidiary Caracol Petroleum LLC (36.28 percent), TP North Slope Development LLC (22.46 percent), Mustang Operations Center 1 LLC (20 percent), MEP Alaska LLC (10.37 percent), Ramshorn Investment Inc. (6.08 percent), AVCG LLC (3.82 percent) and Mustang Road LLC (1 percent).

'Very high level'

At the time of the deal, BRPC expected to drill three wells toward the end of 2014, undertake facilities construction throughout 2015 and bring the field online in early 2016.

The company saw the project as a potential anchor for future development between the Kuparuk River unit and the Colville River unit, a region that ARCO Alaska once evocatively labeled the "billion-dollar fairway." Although BRPC originally considered building a 7,500 barrel per day facility, the company eventually doubled the capacity to 15,000 bpd to accommodate potential third-party shippers in the region.

BRPC completed an initial three-well drilling program in early 2015. All three wells faced complications, making them unusable for production without additional work. A subsequent "root cause analysis" determined that the company needed to acquire a new rig or significantly modify its existing rig to accommodate high pressure in the reservoir.

Analyzing and addressing the problem occupied the remainder of 2015 and the first half of 2016. By late May 2016, Laasch said the company would be ready to resume its drilling program at Mustang with a modified rig sometime in the second quarter of 2017.

BRPC recently told the state that it was currently discussing its needs with contractors and would schedule the retrofitting project with an eye toward the late

continued on page 26

BROOKS RANGE *continued from page 25*

2017 startup date.

Earlier this year, the Alaska Department of Natural Resources extended the term of the Southern Miluveach unit agreement until December 2017 to accommodate the delay.

In the most recent plan of development released in late September 2016, BRPC presented a timeline for bringing Mustang online between October and December 2017. The company described its current timeline as a "very high level" assessment based on its current understanding of the field and current economic conditions within Alaska.

Roads and pads for the project were completed in 2013 and most of the above ground pipeline supports were installed in early 2015. Engineering work on the Mustang Operations Center No. 1 processing facilities was about 65 percent complete when BRPC slowed its timeline in the third quarter of last year. Before the slowdown, BRPC contractors in Canada completed fabrication of the oil train modules, the gas compression train and gas conditioning train. The modules are currently staged in Calgary and Nisku, Alberta, according to the company. BRPC also finished procuring much of the long-lead engineering equipment that it had ordered before it slowed down the project. The equipment is being stored at three facilities in Anchorage, according to BRPC.

The company expects Mustang to initially produce approximately 6,000 barrels per day and gradually increase to a peak of 12,000 bpd by late 2018 and into 2019.

Another reason for the slowdown, according to BRPC, was that the downturn in oil prices made it difficult to attract capital. If funding comes through before the end of this year, the company expects to resume the engineering and procurement activities that were stalled last year and begin the process of finding fabrication and installation contractors.

According to the most recent timeline, BRPC will install communication infrastructure toward the end of this year and build early operations centers and camps early next year.

Prior to the expected arrival of the first Alaska-fabricated modules in April 2017, the company plans to complete pipeline installation and interconnection and some remaining pad work. The last Alaska-fabricated modules are expected in September 2017, with the Canadian-fabricated modules arriving in August 2017 and installed by October 2017, providing two-to-three months for conducting the final system-wide review of facilities.

The company expects Mustang to initially produce approximately 6,000 barrels per day and gradually increase to a peak of 12,000 bpd by late 2018 and into 2019. A third-party evaluation suggests 24.7 million barrels of proved oil reserves, almost 44 million barrels of probable reserves and 51 million barrels of possible reserves.

Economics

A major challenge for the project is the combination of oil prices and tax credits.

When BRPC announced the Mustang discovery in early 2012, the prevailing price of Alaska North Slope crude oil was more than $120 per barrel. Speaking to the Commonwealth North Energy Action Coalition in June 2014, then-Chief Operating Officer Bart Armfield said that the project would be "viable" between $80 and $120 per barrel. In his presentation to the Alaska Support Industry Alliance in May 2016, when oil prices were approximately $46 per barrel, Laasch said the company was committed to bringing the project online at any price but was looking for $50 per barrel or higher.

The Southern Miluveach unit benefits from its location. It sits along the southwestern border of the Kuparuk River unit, and the Mustang development is less than one thousand feet from the Alpine oil pipeline, which follows a series of pipelines to the trans-Alaska oil pipeline and outside markets. The ASRC Exploration LLC-operated Placer unit is immediately to the north, providing a potential future customer for facilities.

As of May 2016, Laasch said the company expected to spend another $8 million on field engineering, $25 million on fabrication and $33 million on the installation of facilities on the field pad, in addition to $145 million already spent between December 2014 and November 2015 — $85 million for surface facilities and $60 million for drilling wells. ●

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Caelus suspends program in the face of low oil

After a busy year in 2015, Oooguruk operator is taking a more cautious approach

By ERIC LIDJI
For Petroleum News

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Earlier this year, as a response to persistently low crude oil prices, Caelus Natural Resources Alaska LLC reduced its workforce by 25 percent, suspended near-term drilling at the Oooguruk unit and postponed plans to develop the associated Nuna project.

JAMES MUSSELMAN

Those measures followed nearly a decade of growth and stability at the North Slope field.

As of mid-June 2016, Caelus and its predecessor Pioneer Natural Resources Alaska Inc. had drilled 43 wells at the Oooguruk unit. A third of those had been drilled within the last three years — five each during the seventh (June 2013 to August 2014), eighth (September 2014 to August 2015) and ninth (September 2015 to August 2016) plans of development.

The advancement of the Nuna project represented a major expansion after several years of exploration, appraisal and technical review at the offshore Beaufort Sea oil field.

Caelus is not planning any drilling or workover activities at Oooguruk under the 10th plan of development, which runs through August 2017. Still, the company has expressed longer-term confidence in the health of the Oooguruk unit, saying it would resume its previous drilling program "when oil prices recover and investor confidence resumes."

But when Petroleum News asked the company about its general outlook in August 2016, Caelus Alaska Director of Public Af-

continued on page 28

CAELUS *continued from page 27*

fairs Casey Sullivan cited oil prices, the Alaska fiscal system and the recent veto of state tax credits as reasons for pessimism: "Those (issues) all go into the final hopper for planning and none of those are looking overly optimistic," Sullivan said. "We're continuing to evaluate our future plan and are hopeful for an additional price uptick and a time when we see some certainty in the fiscal system."

According to the Alaska Oil and Gas Conservation Commission, Pioneer and Caelus drilled two wells at Oooguruk in 2014, and Caelus drilled six wells in 2015 and two wells through in 2016 through September. Caelus also drilled two exploration wells this year in the remote Smith Bay, suggesting some optimism about future North Slope opportunities.

Even with the fluctuation in drilling, the Oooguruk unit continues to produce steadily. At the start of 2014, the unit had produced some 14.8 million barrels, according to the AOGCC. A year later, at the start of 2015, total production was up 4.1 million to 18.9 million barrels. By the start of this year, total production was again up 4.2 million to 23.1 million barrels. Oooguruk produced 2.5 million barrels in the first six months of this year, which means that the unit is on pace for a notable increase over 2015, if the rate holds.

Change of plans

Caelus was planning a regular development program for this year as recently as early February 2016. In light of a late 2015 request to expand the Oooguruk Nuiqsut participating area at the unit, company officials met with officials from the state Division of Oil and Gas to discuss upcoming drilling plans. The company met with state officials again in late April 2016 to review their work plan, after deciding to suspend activities.

Even though the changes at Oooguruk were announced over a short period of time in early 2016, earlier announcements in recent years suggested some economic challenges.

When Caelus was acquiring the Oooguruk unit from Pioneer in late 2013 and early 2014, the company expressed great enthusiasm about pursuing the Nuna development. The project involved building a new drilling pad and associated facilities at Oliktok Point to develop an accumulation in the Torok formation estimated to contain between 75 million and 100 million barrels. After closing on the acquisition and studying the project in greater depth, Caelus decided it would need some form of state assistance to make the $1.4 billion project economic. In return for work commitments, the state reduced the royalty rate on five leases at the development to 5 percent until Caelus recovered upfront costs.

During the first half of 2015 Caelus "fully sanctioned" the Nuna project. The company installed the Nuna Drill Site 1 drilling pad and an associated access road, continued engineering for onshore production facilities and ordered long lead items. In the second half of the year, the company commissioned a 3-D seismic survey over some 70 square miles over the region and began permitting a potential Nuna Drill Site 2 pad.

But in December 2015, Caelus decided it would postpone flowline installation and facilities fabrications by one winter. Even with the delay, the company still believed it could meet its initial deadline for bringing the project into production by late 2017. That timeline has slipped. In the 10th plan of development, Caelus said it would continue facility design, geologic and geophysical analyses and long lead procurement over the coming year, in preparation for construction in early 2018 and startup "in 2018 or later."

Before the current drop in oil prices, Caelus investor Apollo Global Management told the company to hedge its oil price position, according to Caelus Energy Alaska Senior Vice President Pat Foley. The hedge is expected to continue through most of 2017. Although the company reduced its expenses, Foley described the move as a way to position for the future, saying that the company is planning for a 30- to 40-year field life at Oooguruk.

Smaller and faster

Oooguruk was a symbol of change on the North Slope during the 2000s.

Through the first three decades of North Slope development, international oil companies undertook several major projects in the region and demanded massive discoveries to justify their considerable investments. By the turn of the century, the maturing basin was attracting smaller companies who wanted to use the existing grid of infrastructure across the North Slope to pursue relatively "smaller" discoveries overlooked by the majors.

ARCO Alaska Inc. discovered the Oooguruk field in 1992, and independent Armstrong Oil & Gas Inc. delineated the "Northwest Kuparuk" prospect in the early 2000s. Through a series of deals, Pioneer acquired a 70 percent interest in the leases and became operator of the unit while Italian major Eni Petroleum acquired the remaining 30 percent interest.

After just five years of work, Pioneer brought the nearshore Oooguruk unit into production in June 2008, becoming the first independent producer on the North Slope.

In its nearly six years as operator, Pioneer developed three pools: the Nuiqsut, Kuparuk and Torok, from deepest to shallowest. The Nuiqsut was the largest of the three and continues to attract the majority of the investment when it comes to drilling.

In late 2013, after delineation drilling encountered a large reservoir in the southern end of the unit, and newly implemented completion techniques increased production from existing wells, Pioneer sold the Oooguruk unit to Caelus to focus on Lower 48 properties.

Caelus comes from a group of executives with a history of short-term projects, such as the acquisition, turnaround and sale of a struggling independent called Triton Energy in the 1990s and the creation and initial public offering of Kosmos Energy in 2011. ●

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ConocoPhillips easing plans on Slope

Development slower than 2015 pace but company eyes near-term projects

By ERIC LIDJI
For Petroleum News

With the recent marketing of its legacy Cook Inlet fields, and the suspension of its offshore activities in the Arctic Ocean, ConocoPhillips Alaska Inc. is focusing almost exclusively on its onshore North Slope properties for the immediate future.


JOE MARUSHACK

And while the company has been perhaps the most enthusiastic operator on the North Slope in recent years, it is also making adjustments in response to current oil prices.

ConocoPhillips operates the Kuparuk River and Colville River units and is a working interest owner at the BP-operated Prudhoe Bay unit. In the National Petroleum Reserve-Alaska, ConocoPhillips operates the non-producing Greater Mooses Tooth unit and Bear Tooth unit. While the company sold its stake in the Beluga River unit to a pair of Southcentral utilities, the company still operates the North Cook Inlet unit. The legacy offshore field was also being marketed for sale but had not been sold by September 2016.

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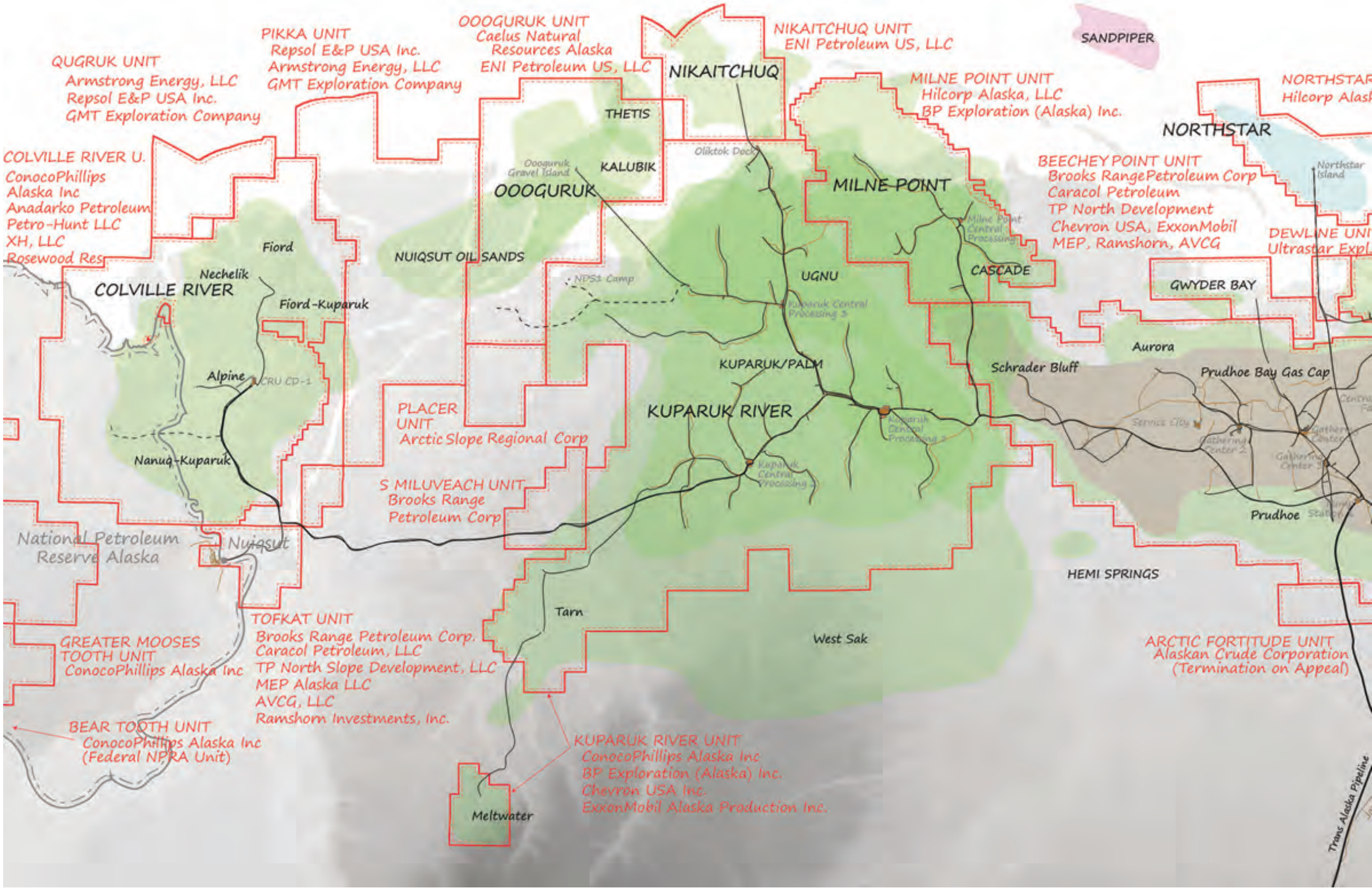
The Kuparuk field

Over the past few years, ConocoPhillips has been mitigating production declines at the Kuparuk River unit through a combination of two approaches: an infill program of coiled-tubing drilling sidetracks and multilateral wells, and infrastructure-led exploration.

When oil prices began to decline and stay low, ConocoPhillips was in the middle of a considerable expansion in development drilling at the unit. The company drilled 58 wells at Kuparuk in 2014 and 76 wells in 2015, according to Alaska Oil and Gas Conservation Commission records. Through the first six months of

continued on page 33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OOOGURUK UNIT
Caelus Natural
Resources Alaska
ENI Petroleum US, LLC
NIKAITCHUQ UNIT
ENI Petroleum US, LLC
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NIKAITCHUQ
THETIS
MILNE POINT UNIT
Hilcorp Alaska, LLC
BP Exploration (Alaska) Inc.
NORTHSTAR
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NORTHSTAR
COLVILLE RIVER U.
ConocoPhillips
Alaska Inc
Anadarko Petroleum
Petro-Hunt LLC
XH, LLC
Rosewood Res
KALUBIK
OOOGURUK
Oliktok Dock
MILNE POINT
BEECHEY POINT UNIT
Brooks Range Petroleum Corp
Caracol Petroleum
TP North Development
Chevron USA, ExxonMobil
MEP, Ramshorn, AVCG
DEWLINE UNI
Ultrastar Expl
Fiord
Nechelik
COLVILLE RIVER
Fiord-Kuparuk
NUIQSUT OIL SANDS
UGNU
CASCADE
GWYDER BAY
Aurora
KUPARUK/PALM
Schrader Bluff
Prudhoe Bay Gas Cap
Alpine
CRU CD-1
PLACER
UNIT
Arctic Slope Regional Corp
KUPARUK RIVER
Nanuq-Kuparuk
S MILUVEACH UNIT
Brooks Range
Petroleum Corp
Prudhoe
National Petroleum
Reserve Alaska
Nuiqsut
HEMI SPRINGS
Tarn
TOFKAT UNIT
Brooks Range Petroleum Corp.
Caracol Petroleum, LLC
TP North Slope Development, LLC
MEP Alaska LLC
AVCG, LLC
Ramshorn Investments, Inc.
GREATER MOOSES
TOOTH UNIT
ConocoPhillips Alaska Inc
West Sak
ARCTIC FORTITUDE UNIT
Alaskan Crude Corporation
(Termination on Appeal)
BEAR TOOTH UNIT
ConocoPhillips Alaska Inc
(Federal NPRA Unit)
KUPARUK RIVER UNIT
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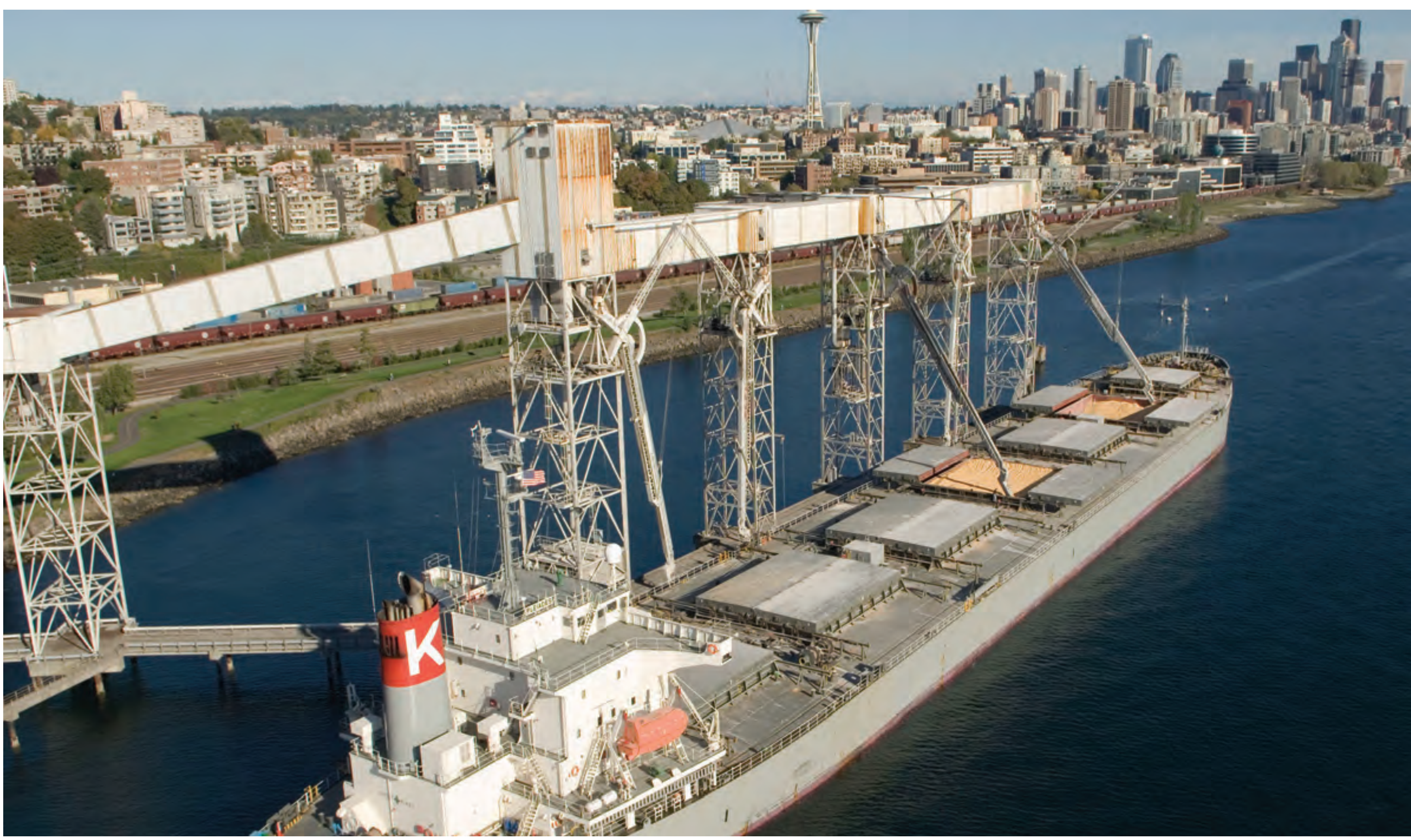
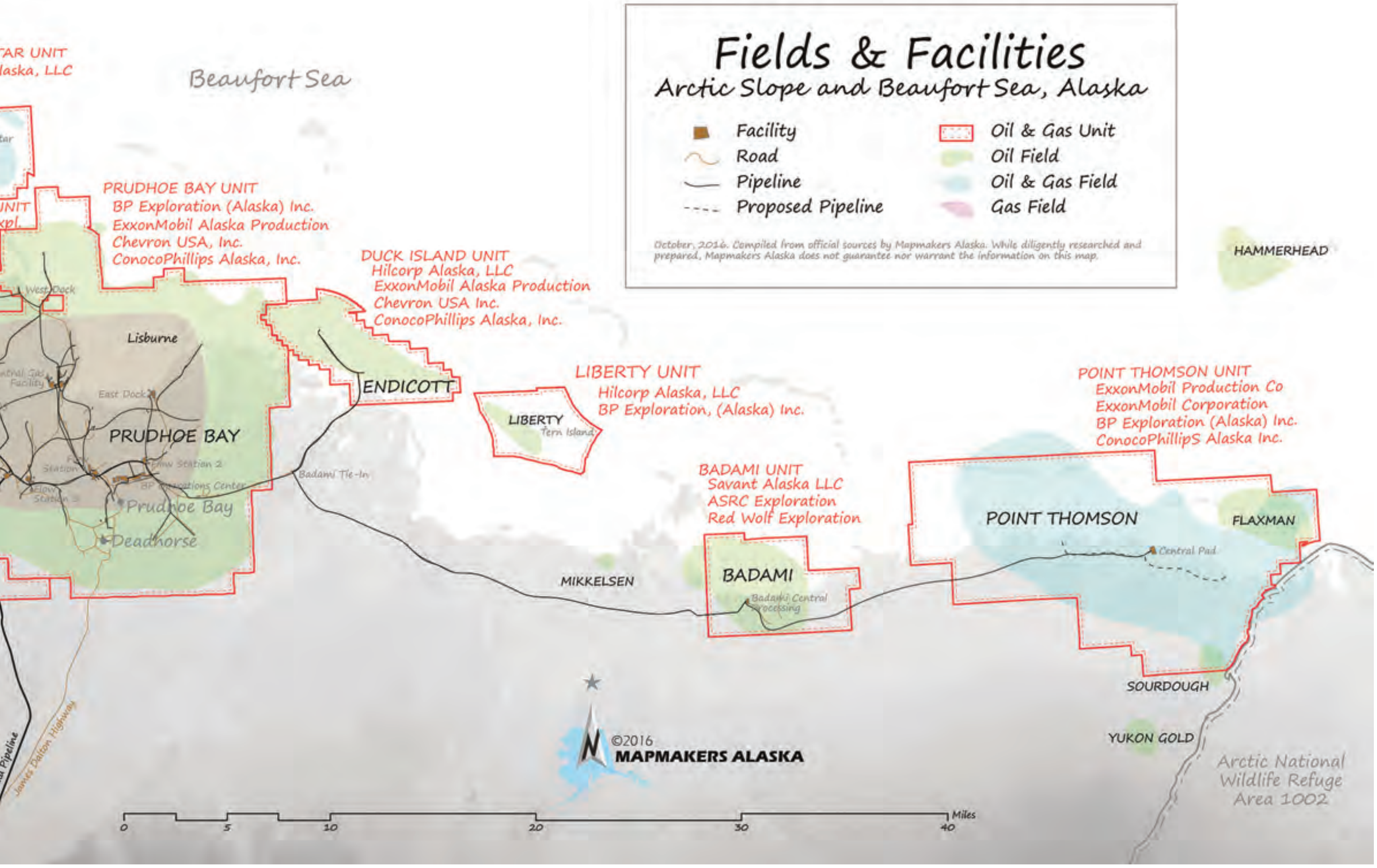
BP Exploration (Alaska) Inc.
Chevron USA Inc.
ExxonMobil Alaska Production Inc.
Meltwater
Trans Alaska Pipeline




Fields & Facilities
Arctic Slope and Beaufort Sea, Alaska
Facility
Road
Pipeline
Proposed Pipeline
Oil & Gas Unit
Oil Field
Oil & Gas Field
Gas Field
October, 2016. Compiled from official sources by Mapmakers Alaska. While diligently researched and prepared, Mapmakers Alaska does not guarantee nor warrant the information on this map.
Beaufort Sea
PRUDHOE BAY UNIT
BP Exploration (Alaska) Inc.
ExxonMobil Alaska Production
Chevron USA, Inc.
ConocoPhillips Alaska, Inc.
DUCK ISLAND UNIT
Hilcorp Alaska, LLC
ExxonMobil Alaska Production
Chevron USA Inc.
ConocoPhillips Alaska, Inc.
West Dock
Lisburne
East Dock
ENDICOTT
PRUDHOE BAY
Prudhoe Bay
Deadhorse
Badami Tie-In
LIBERTY UNIT
Hilcorp Alaska, LLC
BP Exploration, (Alaska) Inc.
LIBERTY
Tern Island
BADAMI UNIT
Savant Alaska LLC
ASRC Exploration
Red Wolf Exploration
BADAMI
Badami Central Processing
MIKKELSEN
POINT THOMSON UNIT
ExxonMobil Production Co
ExxonMobil Corporation
BP Exploration (Alaska) Inc.
ConocoPhillips Alaska Inc.
POINT THOMSON
Central Pad
FLAXMAN
HAMMERHEAD
SOURDOUGH
YUKON GOLD
Arctic National Wildlife Refuge Area 1002
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MAPMAKERS ALASKA
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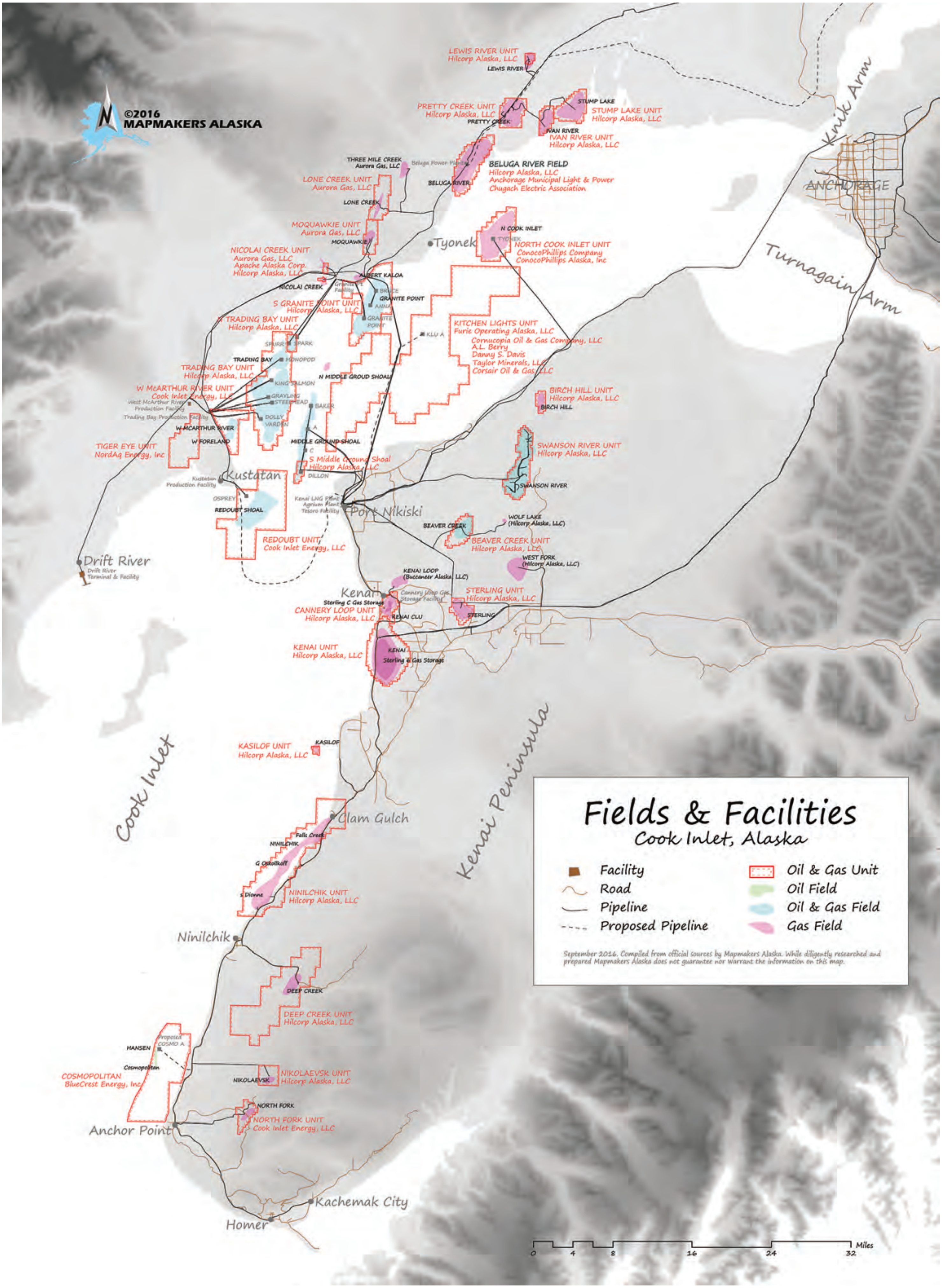

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Fields & Facilities
Cook Inlet, Alaska
Facility
Road
Pipeline
Proposed Pipeline
Oil & Gas Unit
Oil Field
Oil & Gas Field
Gas Field
September 2016. Compiled from official sources by Mapmakers Alaska. While diligently researched and prepared Mapmakers Alaska does not guarantee nor warrant the information on this map.
0 4 8 16 24 32 Miles
LEWIS RIVER UNIT Hilcorp Alaska, LLC
LEWIS RIVER
PRETTY CREEK UNIT Hilcorp Alaska, LLC
PRETTY CREEK
STUMP LAKE
STUMP LAKE UNIT Hilcorp Alaska, LLC
IVAN RIVER
IVAN RIVER UNIT Hilcorp Alaska, LLC
THREE MILE CREEK Aurora Gas, LLC
Beluga Power Plant
BELUGA RIVER
BELUGA RIVER FIELD Hilcorp Alaska, LLC Anchorage Municipal Light & Power Chugach Electric Association
LONE CREEK UNIT Aurora Gas, LLC
LONE CREEK
MOQUAWKIE UNIT Aurora Gas, LLC
MOQUAWKIE
Tyonek
N COOK INLET
TYONEK
NORTH COOK INLET UNIT ConocoPhillips Company ConocoPhillips Alaska, Inc
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ALBERT KALOA
GRANITE POINT
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ANNA
S GRANITE POINT UNIT Hilcorp Alaska, LLC
N TRADING BAY UNIT Hilcorp Alaska, LLC
SPURR
SPARK
KLU A
KITCHEN LIGHTS UNIT Furie Operating Alaska, LLC Cornucopia Oil & Gas Company, LLC A.L. Berry Danny S. Davis Taylor Minerals, LLC Corsair Oil & Gas, LLC
TRADING BAY
MONOPOD
TRADING BAY UNIT Hilcorp Alaska, LLC
N MIDDLE GROUD SHOAL
KING SALMON
W McARTHUR RIVER UNIT Cook Inlet Energy, LLC
West McArthur River Production Facility
Trading Bay Production Facility
GRAYLING
STEELHEAD
DOLLY VARDEN
BAKER
W MCARTHUR RIVER
W FORELAND
BIRCH HILL UNIT Hilcorp Alaska, LLC
BIRCH HILL
MIDDLE GROUND SHOAL
TIGER EYE UNIT NordAq Energy, Inc
S Middle Ground Shoal Hilcorp Alaska, LLC
DILLON
SWANSON RIVER UNIT Hilcorp Alaska, LLC
SWANSON RIVER
Kustatan
Kustatan Production Facility
OSPREY
REDOUBT SHOAL
Kenai LNG Plant Agrium Plant Tesoro Facility
Port Nikiski
BEAVER CREEK
WOLF LAKE (Hilcorp Alaska, LLC)
BEAVER CREEK UNIT Hilcorp Alaska, LLC
REDOUBT UNIT Cook Inlet Energy, LLC
WEST FORK (Hilcorp Alaska, LLC)
Drift River
Drift River Terminal & Facility
KENAI LOOP (Buccaneer Alaska, LLC)
Kenai
Cannery Loop Gas Storage Facility
STERLING UNIT Hilcorp Alaska, LLC
Sterling C Gas Storage
CANNERY LOOP UNIT Hilcorp Alaska, LLC
KENAI CLU
STERLING
KENAI UNIT Hilcorp Alaska, LLC
KENAI
Sterling 6 Gas Storage
Knik Arm
ANCHORAGE
Turnagain Arm
Cook Inlet
Kenai Peninsula
KASILOF UNIT Hilcorp Alaska, LLC
KASILOF
Clam Gulch
Falls Creek
NINILCHIK
G Oskolkoff
S Dionne
NINILCHIK UNIT Hilcorp Alaska, LLC
Ninilchik
DEEP CREEK
DEEP CREEK UNIT Hilcorp Alaska, LLC
HANSEN
Proposed COSMO A
Cosmopolitan
COSMOPOLITAN BlueCrest Energy, Inc
NIKOLAEVSK
NIKOLAEVSK UNIT Hilcorp Alaska, LLC
NORTH FORK
NORTH FORK UNIT Cook Inlet Energy, LLC
Anchor Point
Kachemak City
Homer

CONOCOPHILLIPS *continued from page 29*

2016, the company drilled 30 wells at the unit — slower than the pace of drilling in 2015 but faster than the pace in 2014.

The AOGCC figures classify each lateral in a multilateral well separately, which means the number of vertical wellbores is significantly fewer than the actual penetrations. Using figures provided by the company in its plans of development, ConocoPhillips drilled 26 vertical wells with 40 laterals in 2014 and 28 vertical wells with 48 laterals in 2015. In the first six months of 2016, the company drilled nine vertical wells with 21 laterals.

ConocoPhillips produced 110,700 barrels per day at Kuparuk in 2013, 110,200 bpd in 2014 and 104,600 bpd in 2015, according to the company.

Those figures indicate an accelerating rate of decline: down 0.4 percent between 2013 and 2014 and down 5 percent between 2014 and 2015. The declines were sharper at the main Kuparuk field, where ConocoPhillips produced 85,700 bpd in 2013, 83,200 bpd in 2014 and 78,200 bpd in 2015 — a 2.9 percent decline between 2013 and 2014 and a 6 percent decline between 2014 and 2015. At the four satellites, ConocoPhillips produced 25,000 bpd in 2013, up to 27,000 bpd in 2014 and down to 26,400 bpd in 2015.

The infrastructure-led exploration strategy has yielded two big projects in recent years.

An appraisal well in the southwest corner of the unit prompted ConocoPhillips to construct Drill Site 2S — the first new drilling pad at the unit in more than a decade.

ConocoPhillips brought the drilling pad into production in October 2015 and drilled one production well and five injection wells from the pad in the southwest corner of the unit through the remainder of the year and three more production wells through May 2016.

According to its initial plans, ConocoPhillips expects to drill 14 development wells from the drilling pad for the time being, although the facility can handle as many as 24. The $475 million project should eventually yield peak production of 8,000 barrels per day.

At the opposite corner of the unit, ConocoPhillips is in the early stages of expanding Drill Site 1H to develop the North East West Sak accumulation. While ConocoPhillips originally intended to begin the 1H NEWS program at Drill Site 1H this year, the company deferred the program in mid-2016 "based on market conditions." Prior to making the decision, the company had already completed "much of the surface work to expand the existing DS1H gravel pad and facilities to accommodate the 19 new wells."

Those investments give ConocoPhillips a reason to proceed quickly, should oil prices increase. And, if those hypothetical increases persist for a significantly period of time, ConocoPhillips believes the North East West Sak accumulation provides other opportunities for development, including projects at existing Drill Site 3K and Drill Site 3N, an expansion of Drill Site 3R to target offshore accumulations from the onshore facilities at Oliktok Point and a new drilling pad to target the "Eastern NEWS" development.

A third opportunity exists along the western edge of the unit, in the vicinity of Drill Site 3S. ConocoPhillips drilled two wells in the area in 2015 to appraise the potential of the overlying Cretaceous Brookian Moraine interval near the former Palm satellite.

ConocoPhillips drilled the vertical Moraine 1 well from an ice pad "to acquire extensive logs with whole core for detailed reservoir and overburden characterization studies, including special core analysis." The company plugged and abandoned the well after operations were complete. The company also drilled and completed the horizontal 3S-620 production well from Drill Site 3S. Earlier this year, the company returned to drill the corresponding 3S-613 injection well. "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.

The Alaska Oil and Gas Conservation Commission approved pool rules for the Kuparuk River-Torok Oil Pool in July 2016, allowing ConocoPhillips to proceed with a 10-to-40-well initial development program from the existing DS-3S. Early indications suggest ConocoPhillips is planning "distinct phases" for developing the pool and would start at the low end of that range. But the company told state officials it could potentially build between one and two additional pads in the area to target

continued on page 34

CONOCOPHILLIPS *continued from page 33*

other sections of the pool.

According to AOGCC estimates, the development from DS-3S could access between 100 million and 500 million barrels of oil in place from the Torok formation, and a development from an additional pad could access another 100 million to 300 million barrels of oil in place. The commission estimated a 5 percent primary recovery rate and a recovery rate between 13 and 55 percent using certain enhanced recovery techniques.

But while ConocoPhillips believes "appraisal and exploration opportunities exist" within the Kuparuk River unit, the company made no specific plans for new ventures this year.

The Kuparuk satellites

In recent years, the four Kuparuk River unit satellites — West Sak, Tarn, Tabasco and Meltwater — have helped offset or mitigate declines at the main Kuparuk oil field. But ConocoPhillips appears to be reducing its operations in the satellites for the short term, even as it sometimes hints at opportunities it wants to pursue at some point in the future.

ConocoPhillips drilled eight West Sak wells from Drills Site 1D and Drill Site 1C in 2015. The 1D program included the single-lateral injector 1D-142, the quad-lateral producer 1D-143, the single-lateral producer 1D-145 and the single-lateral producer 1D-146. The company is considering additional wells from the pad, pending the results of the recent program. The 1C program included the single-lateral injector 1C-152, the single-lateral producer 1C-153, the single-lateral injector 1C-154 and the single-lateral producer 1C-155. The company is considering three additional "lower value" targets from the pad.

But while ConocoPhillips believes "appraisal and exploration opportunities exist" within the Kuparuk River unit, the company made no specific plans for new ventures this year.

Even with those additional wells, West Sak production declined to some 13,865 barrels per day in 2015, down from 16,241 bpd in 2014 and 15,772 bpd in 2013.

All six of the drilling sites currently being used to target the satellite are developing both the West Sak and North East West Sak participating areas and any new development will likely require facility upgrades. "These additional facility requirements add to the economic challenge of further West Sak/NEWS development in the current business environment," ConocoPhillips wrote in its current plan of development.

ConocoPhillips is also planning to take a hiatus from its recent activities at the Tarn satellite this year, after completing a successful nine-well program in 2014 and a five-well program in 2015. Those two programs yielded significant results. Tarn production increased to 9,300 barrels per day in 2015, up from 7,700 bpd in 2014 and 5,600 bpd in 2013.

Between April and December 2015, the company brought four production wells and one injection well into operation from Drill Site 2L and Drill Site 2N, adding some 477,000 barrels of oil production at a combined rate of 1,050 bpd in December 2015.

But even with the recent success at Tarn, ConocoPhillips is planning no development drilling at the satellite under its current development plan, which expires at the end of July 2017. The company is evaluating recent drilling results to identify future projects.

The drilling programs at Tarn in 2014 and 2015 only delineated the Bermuda interval, and two other intervals could provide opportunities: the older Purple interval, which has seen "encouraging" results from other wells, and the younger Cairn interval. In previous plans of development, the company has also mentioned the Esker interval.

The Tabasco and Meltwater satellites have received much less investment than West Sak or Tarn in recent years, and ConocoPhillips has no development drilling planned for either satellite in the coming year. Even so, production increased at both satellites in 2015. Tabasco produced 1,619 barrels per day in 2015, up from 1,549 bpd in 2014 and down from 1,711 barrels per day in 2013. Meltwater produced 1,569 bpd in 2015, up from 1,439 bpd in 2014 and down from 1,971 bpd in 2013.

The Colville River unit

As has been the case since Philips Inc. brought the unit online in 2000, development at the Colville River unit is continuing to proceed in a step-by-step manner to the west.

That westward march was stalled for several years while ConocoPhillips battled regulators over plans for its CD-5 pad, but with those debates resolved and the pad now operational, drilling has been increasing. The company drilled six wells at the unit in 2014, 10 wells in 2015 and 13 wells in the first nine months of 2016. Initially, ConocoPhillips planned to drill 15 wells in its first phase of development at the CD-5 pad. But in late April 2016, after reviewing results from the first 10 wells from the pad, the company announced plans to more than double the development to 33 wells.

The CD-5 program should increase overall production from the Colville River unit. The unit produced some 51,100 barrels per day on average, some 18.3 million barrels total in 2014, and some 50,500 bpd on average and 18 million barrels total in 2015.

Through the first six months of 2016, the unit produced approximately 11.1 million barrels, which would put the unit on pace for a notable increase over 2015 levels.

According to the AOGCC, ConocoPhillips drilled 12 wells at the unit between May 2015 and mid-April 2016, and all from the CD-5 pad. The drilling program included nine producers (CD5-03, CD5-04, CD5-05, CD5-09, CD5-10, CD5-11, CD5-21, CD5-315 and the suspended CD5-314 well) and three injectors (CD5-01, CD5-07 and CD5-313).

The CD5-313 well (which ConocoPhillips said is associated with the CD5-314 well) was a horizontal producer into the Nanuq Kuparuk. The CD5-315 well was an associated horizontal injector. (The CD5-313 well is listed as an injector in AOGCC records and a producer in the plan of development and the CD5-315 well is listed as a producer in AOGCC records and an injector in the plan of development.) The CD5-313 well accounted for "the majority of Nanuq Kuparuk production" in December 2015, according to the company. Given those positive results, ConocoPhillips plans to drill the CD5-SUN3 well in the second half of this year. With positive results, the company might drill an additional Nanuq Kuparuk well, CD5-SUN4, between the mid-2016 and early 2017.

ConocoPhillips drilled eight more CD5 wells between May and September 2016.

Greater Mooses Tooth

The primary regulatory hang-up for the CD-5 project concerned a bridge crossing a channel of the Colville River, and the resolution of that matter allowed ConocoPhillips to proceed with two immediate development projects even farther west, into the Greater Mooses Tooth unit at the eastern edge of the National Petroleum Reserve-Alaska.

The U.S. Bureau of Land Management approved the GMT-1 development in February 2015. ConocoPhillips later sanctioned the $900 million project and expects production by 2018. BLM launched its environmental review of the GMT-2 project in July, which means that approval or denial and a subsequent decision

continued on page 36

CONOCOPHILLIPS *continued from page 35*

about sanctioning is a ways off.

To ease that stepwise development, ConocoPhillips asked the state earlier this year to expand the Colville River unit to make its border contiguous with Greater Mooses Tooth.

And ConocoPhillips is continuing exploration activities on lands beyond those developments. While those activities include plans for exploring the western edge of the Greater Mooses Tooth unit, they could also mean activities on state owned acreage.

Earlier this year, ConocoPhillips acquired a portion of the leases from the former Tofkat unit. Those leases were briefly a part of the Colville River unit in 2002 but were relinquished after ConocoPhillips failed to meet drilling commitment associated with the expansion. If ConocoPhillips builds up the lease position, it could presage a new satellite.

> *"These additional facility requirements add to the economic challenge of further West Sak/NEWS development in the current business environment," ConocoPhillips wrote in its current plan of development.*

North Cook Inlet

After completing a three well program at the North Cook Inlet unit in 2008, ConocoPhillips reduced its development program at the offshore field in Cook Inlet.

A decline in reservoir pressure across most of the field and increased sand production in places have contributed to an overall decline in production since the drilling program.

The unit has traditionally been connected to the Kenai liquefied natural gas facility in Nikiski. Activity at the plant has been sporadic in recent years. ConocoPhillips shipped five cargoes between May and September 2014 and six cargoes between May and mid-October 2015. The company made no shipments in the first quarter of 2016, despite receiving U.S. Department of Energy permission to continue exports from the facility.

Instead, the company is selling North Cook Inlet production into the local market.

By the start of 2014, the North Cook Inlet unit had produced 1.879 trillion cubic feet of natural gas. The unit produced 9.29 billion cubic feet that year and 7.33 bcf in 2015 for a total of 1.896 trillion cubic feet at the start of this year. In the first six months of 2016, the unit produced 3.58 bcf, which suggest a decline from 2015 production levels, although not as steep as the decline between 2014 and 2015.

The slowdown in declining production this year might be the result of a four-well workover program and other maintenance projects ConocoPhillips undertook at the North Cook Inlet unit in 2015. When the company released its plan for 2016, it proposed no such work for this year but looked forward to a possible workover program in 2017.

The actual plan for 2017, released in early October 2016, provided few details, noting "The team continues to evaluate future rig work-over and/or drilling opportunities" and "ConocoPhillips plans to continue to evaluate potential undeveloped accumulations." ●

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Eni expects new Nikaitchuq drilling in 2017

Royalty relief failed to prevent a suspension of drilling activities for most of 2016

By ERIC LIDJI
For Petroleum News

When Eni Petroleum was deciding whether to sanction the Nikaitchuq unit, in 2007, the state of Alaska agreed to reduce the royalty rate during periods of low oil prices. That relief helped convince the Italian major to pursue the offshore North Slope project, which surpassed 30 million barrels of cumulative oil production earlier this year.

The basic trigger price for the reduction was $42.64 per barrel, which seemed hard to imagine at the time. The average spot price of Alaska North Slope crude oil was about $85 per barrel in late 2007, on its way to a record high of more than $140 per barrel.

Over the past two years, oil prices have sometimes hovered just above the trigger for royalty relief and sometimes fallen far below it. Even with the occasional assistance, Eni suspended drilling at the unit and reduced its workforce by 10 percent in 2015 "due to the current oil price environment" and kept its rigs idle for most of 2016. The company is planning to resume its drilling operations in early 2017, "with hopes of a more favorable oil prices environment," the company told state officials in a recent plan of development. As described to the state, the 2017 program would include 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 could convert as many as eight wells to multilaterals.

According to Alaska Oil and Gas Conservation Commission records, Eni drilled 13 wells at Nikaitchuq in 2014, 10 wells at the unit in 2015 and none in 2016 through September.

Even with the decline in drilling, production remains strong. At the start of 2014, the Nikaitchuq unit had produced some 9.8 million barrels. By the start of 2015, production was up 8.3 million barrels to 18.1 million. By the start of this year, production was up 8.9 million barrels to 27 million. In the first six months of 2016, the unit produced 4.5 million barrels. If the unit keeps pace in the second half, production will rise over 2015.

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Expansions

The suspension came as the Nikaitchuq unit was beginning a transition. Eni is nearly finished with its initial drilling program and has been studying ways to improve or increase production rates

continued on page 38

ENI PETROLEUM *continued from page 37*

through geographic expansion and more efficient well design.

Eni has been developing Nikaitchuq from two pads — the onshore Oliktok Point pad and the offshore Spy Island drill site. The company completed its initial drilling program at Oliktok Point in October 2012 and began a continuous drilling program from Spy Island in November 2012 using Doyon rig 15. The Spy Island program continued until the company suspended drilling operations in December 2015, due to low oil prices.

When the company resumes development, one of its tasks will be to finally complete the initial Spy Island program and formally wrap up its initial development work at the unit.

Between late 2012 and late 2015, though, Eni also started some new ventures.

Starting in mid-2013, Eni began adding laterals to existing wells. The campaign lasted through May 2014 and added eight laterals to select existing Oliktok Point pad wells. 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 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 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.

While those efforts sought to improve production at existing wells, Eni was also attempting to increase production by expanding

When the company resumes development, one of its tasks will be to finally complete the initial Spy Island program and formally wrap up its initial development work at the unit.

into under-developed corners of the unit.

In the third quarter of 2014, Eni launched the West Extension Project to target a specific area west of the Spy Island drill site. The company drilled two dual lateral producers and two single lateral injectors before completing the extension project in 2015. The company launched the East Extension Project in the third quarter of 2015, but only completed one dual lateral producer before suspending development activities a few months later. The remainder of that East Extension Project remains on the docket for the 2017 program.

And earlier this year, federal officials confirmed that Eni was evaluating a North Nikaitchuq project, which would use extended-reach exploration wells to target leases in the federal outer continental shelf, north of the state-owned leases at Nikaitchuq. The company is the owner or partial owner of 29 leases in the outer continental shelf in the areas, and those leases are set to expire at dates between July and December 2017.

Other formations

While those three projects would expand development aerially, or already have, Eni has also been considering a project that would add more intervals and formations to the unit.

Eni sanctioned Nikaitchuq based entirely on the potential of the Schrader Bluff OA sands but early on the company saw an opportunity to develop the shallower N sands. After preliminary studies suggested between 40 million and 100 million barrels of "contingent resources" in the N sands, Eni launched an appraisal program. The company drilled a pilot well in 2013 and hopes to return this year to test a new completion technique.

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 is "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 left the Sag River out of its 2015 and 2016 plans for development. ●

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Exxon starts Point Thomson, questions remain

The long delayed project came online in 2016 but its fate depends on a gas line

By ERIC LIDJI
For Petroleum News

ExxonMobil — one of the earliest explorers in Alaska, and one of the most important working interest owners on the North Slope — finally became a producer this year.

The company began producing natural gas condensate from the Point Thomson unit in April 2016 and is running a cycling program to extract and market liquids from that production and to inject natural gas back into the field to maintain reservoir pressure.

CORY QUARLES

While the startup was a major milestone in the decades-long history of the North Slope unit, much larger forces at work throughout the region are quickly overshadowing it.

Specifically, ExxonMobil is quickly approaching deadlines where it must decide how it will proceed with developing Point Thomson, which could lead to conflict with the state.

The current Initial Production System promises to produce 10,000 barrels of condensate per day once all required infrastructure is operational. Production began from the Point Thomson unit central pad, which is expected to produce some 5,000 barrels per day of condensate and 100 million cubic feet per day of recycled gas, according to the company. When the west pad comes online, the entire Point Thomson facility will produce 10,000 bpd of condensate and 200 million cubic feet of recycled gas.

Through the first few months of reporting, production rates fluctuated as this commissioning process advanced. The Point Thomson unit produced 47,972 barrels of liquids in April 2016, 7,903 barrels in May 2016, 21,276 barrels in June 2016 and 32,893 barrels in July 2016, according to the Alaska Oil and Gas Conservation Commission.

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Field startup

While the startup of the field represented the end of a major ordeal in the history of the Alaska oil industry — with some $4 billion invested and some 11 million work-hours expended, according to the company — the milestone is clearly just the beginning of the story. Should a natural gas pipeline ever be constructed from the North Slope to markets outside the state, the natural gas contained at Point Thomson will play an important part.

Until now, the history of the Point Thomson field can be roughly divided into two eras — the decades before a 2012 settlement between Exxon and the state, and the years since.

Now starts a third phase, where Exxon must follow one of two paths.

The settlement actually included three alternatives. Exxon already passed on the first of those: to sanction major natural gas sales by June 2016. That never happened.

Instead, under Gov. Bill Walker, the state is eager to take the lead on the existing AKLNG project, and is unlikely to decide whether to sanction the project before 2018.

The change in leadership could complicate short-term plans at Point Thomson, considering that the state presumably wants

continued on page 41

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EXXONMOBIL *continued from page 39*

Point Thomson gas available for sale.

The other two options are also tricky.

The second path would have Exxon expand the existing liquids operation to produce 30,000 bpd or more by 2019. The third involves integrating certain operations at the Point Thomson unit and the Prudhoe Bay unit to improve recovery.

When Exxon applied for pool rules at Point Thomson, in September 2015, the company argued against expanding condensate production. Given the high pressure of the reservoir and the low expected yield, the company said that an expansion would be uneconomic.

The current Initial Production System promises to produce 10,000 barrels of condensate per day once all required infrastructure is operational.

By integrating Point Thomson with Prudhoe Bay — using Point Thomson natural gas for field operations at Prudhoe Bay — Exxon could, according to its internal estimates, accelerate the timeline for gas sales by two years. Still, the company insists that those two years would be unlikely to justify the cost of implementing the integration project.

While the state prefers expanding condensate production until a pipeline can accommodate gas sales, Exxon would prefer to transition directly into gas sales.

"The Point Thomson field will provide a foundation for future gas development on the North Slope," ExxonMobil Public and Government Affairs Manager for Alaska Hans Neidig told Petroleum News in an email in early September 2016. "We are working to progress planning for a potential gas expansion concept that would be a supply source for the proposed Alaska LNG project, which is now transitioning to a state project."

Pipeline link

Even without gas sales, Point Thomson will be important in the near term.

As the easternmost producing field on the North Slope, the unit could improve the economics of several prospects on the eastern side of the North Slope, which is one reason why Exxon built its export pipeline to handle 70,000 barrels per day — more than it expects to need.

But that pipeline quickly ruffled feathers.

When Point Thomson Export Pipeline LLC was making its initial administrative filings in 2015, the Exxon-BP transportation joint venture proposed a $20.39 per barrel tariff for using the 22-mile pipeline connecting Point Thomson to the Badami unit to the west.

The state quickly challenged the tariff, claiming that the company inappropriately used the low production rate expected in the first year of operations as the basis for the rate.

The Regulatory Commission of Alaska approved an interconnection allowing the pipeline to be brought into service and approved the tariff on a temporary and refundable basis.

The parties, including future shipper ConocoPhillips, began settlement talks earlier this year. The matter is proceeding simultaneously at both the state and federal level. ●

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Furie taking small bites at big unit

Independent follows Kitchen Lights startup with small development plan to bolster production

By ERIC LIDJI
For Petroleum News

After more than a decade of work by itself and forerunners, Furie Operating Alaska LLC brought the Kitchen Lights unit online from the Julius R platform in November 2015.


ALAN BAILEY
BRUCE WEBB

The startup was a major milestone for the company and also for Cook Inlet. The last offshore platform installed in the region was the Osprey platform, back in 2000.

Bringing the unit online, though, is only the beginning.

At 83,394 acres, the Kitchen Lights unit is by far the largest in the Cook Inlet basin, combining at least three previously distinct offshore prospects into a single administrative entity. Furie is in the early stages of figuring out how to develop such a large area, which includes oil and natural gas prospects in different places and in different formations.

FURIE
Operating Alaska LLC

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Furie spent 2014 and 2015 securing financing for its project and installing the Julius R platform and the associated subsea pipelines to connect to existing onshore facilities.

Earlier this year, Furie launched a four-well development program in the vicinity of the existing KLU No. 3 well. Although KLU No. 3 provided the justification to sanction the Kitchen Lights development, the well cannot effectively drain the entire reservoir or reach the production and deliverability targets to make the project economically viable.

A development program approved by state officials in May 2016 called for Furie to drill two wells during the current open-water season and two more wells in 2017 and 2018.

The Alaska Oil and Gas Conservation Commission issued drilling permits for the Kitchen Light Unit A-2 and Kitchen Light Unit A-1 wells in June 2016. By early September, Furie had completed KLU A-2 and was preparing to start KLU A-1.

The company had also changed its schedule. The plan now calls for splitting KLU A-1 operations over two seasons — starting the well this year and completing it next year. It also calls for completing the Kitchen Light Unit A-3 development well next year.

The shift allows Furie to balance contractual obligations and development goals.

With KLU 3 production currently meeting existing contracts with Homer Electric Association Inc. and Aurora Gas LLC, and KLU A-2 providing an insurance policy for any operational problems, Furie decided it couldn't justify the cost of completing another well this year. The proposed KLU A-1 and KLU A-3 wells would prepare Furie to meet the 2018 start date for a contract with Enstar Natural Gas Co.

Supply and demand

Even with those wells online, Furie needs to continue drilling to meet targets.

The existing subsea pipeline connecting the Julius R platform to onshore facilities can handle as much as 100 million cubic feet per day, and while Furie previously proposed an initial production target of 85 million cubic feet per day, the company has also proposed eventual construction of two 100 million cubic feet per day pipelines, suggesting bigger ambitions. The Homer Electric contract requires Furie to produce between 12 million and 18 million cubic feet of gas per day and the Enstar contract requires between 10 million and 22 million cubic feet per day — for a range between 22 million and 40 million cubic feet per day with additional supplies required to satisfy the smaller Aurora Gas contract.

Increasing production will require Furie to increase both supply and demand.

As far as supplies are concerned, the Kitchen Lights unit has four exploration blocks: North, Corsair, Central and Southwest. The current development from KLU No. 3 targets about 300 acres within the Corsair block. In a plan of operations submitted to the state in March 2016, the company proposed a schedule for drilling as many as 10 exploration wells at the unit in the next five years to target both oil and gas throughout the unit.

Testifying before the state House Resources Committee in March 2016, Furie Chief Financial Officer David Elder told legislators that Furie had spent some $700 million in Alaska over the past five years and expected to spend another $300 million over the next two or three years. Recovering that investment would take seven to 10 years, he said.

Demand poses a trickier challenge and is one reason development plans for Kitchen Lights have been changing over the past two years. In a March 2015 plan of exploration, Furie said it would complete the KLU No. 3 exploration well as a development well and drill two more development wells in the Corsair block by the end of the 2015 drilling season, but would push completion activities on those two additional wells into 2016.

By the time Furie submitted its third plan of development for the unit, in October 2015, the company had scaled back its drilling program. The new plan called for drilling a single additional development well in 2016, citing "market constraints" through 2019.

The date suggested Furie was waiting for several existing Hilcorp Alaska LLC contracts to expire before attempting to expand in the market. Furie Senior Vice President Bruce Webb clari-

continued on page 44

FURIE *continued from page 43*

fied the company's plans in a December 2015 interview with Petroleum News. Rather than drill two wells in 2016 and complete those wells in 2017, he explained, Furie decided it was wiser to drill and complete one well in 2016 and a second well in 2017.

With the Homer Electric contract starting in April 2016, Furie wanted to bring a second well online as soon as possible to backstop KLU No. 3, which was producing some 18 million cubic feet per day by early 2016. After announcing its three-year contract with Enstar Natural Gas Co., Furie accelerated its development plans, saying it would drill two more gas wells this year and two additional wells between April 2017 and October 2018.

To assist with that development program, Furie decided to replace the Spartan 151 jack-up rig with the larger and more powerful Randolf Yost rig from Shelf Drilling Inc. In addition to being safer and more cost-effective, the Randolf Yost rig is capable to drilling deeper wells, allowing Furie to eventually test intervals in the upper Jurassic formation.

To justify any additional drilling, Furie needs assurances of additional markets to purchase increased gas production. Hilcorp currently supplies much of the utility market in Southcentral. While other options exist, such as liquefied natural gas exports and potential industrial applications, they are currently less dependable than utilities.

In addition to competing against the dominant producer in the region, Furie is competing against a group of smaller producers such as AIX Energy Inc., Aurora Gas and Glacier Oil & Gas Corp. BlueCrest Energy is also looking to pursue gas production in the region.

The expected growth in production has placed the Kitchen Lights unit in the middle of a larger battle of transportation infrastructure in the Cook Inlet region. In June 2016, the company confirmed that it was in the early stages of a plan to build a bypass pipeline to reach the Homer Electric Association power plant in Nikiski without having to use the existing Kenai Beluga Pipeline, which could alter tariff rates on the major pipeline. ●

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After bankruptcy, Glacier taking a cautious approach

Subsidiaries Cook Inlet Energy and Savant Alaska still pursuing development

By ERIC LIDJI
For Petroleum News

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After emerging from bankruptcy protection earlier this year, the publicly traded Miller Energy Resources Ltd. became the privately owned Glacier Oil & Gas Corp.

The changes appear to go far beyond name and ownership status. If the first year of activities is any indication, Glacier will be pursuing a different strategy than its predecessor, favoring caution and focus where Miller was ambitious and sprawling.

Following the reorganization, Glacier retained the North Slope and Cook Inlet holdings of Miller Energy, including wholly owned subsidiaries Cook Inlet Energy LLC and Savant Alaska LLC. Through those two companies, Glacier now operates the West McArthur River unit and the nearby Redoubt unit on the west side of Cook Inlet, the North Fork unit in the southern Kenai Peninsula and the Badami unit on the eastern North Slope.

The operating subsidiaries submitted plans of developments for those units as the bankruptcy proceedings were underway, meaning that actual work this year is likely to diverge from proposed plans to a certain extent. While Glacier did not drill any new wells in the first nine months of 2016, the company trimmed some longer-term exploration prospects from its portfolio and began resuming previous efforts to work over existing wells. The plans of developments due over the coming months should provide a much clearer sense of the strategy of the company than its current workload.

According to state records from September 2016, Glacier has nine working interest owners: Apollo Investment Corp. (50 percent), seven affiliates of HPS Investment Partners LLC (48.52 percent collectively) and Lincoln Investment Solutions Inc. (1.48 percent). Among the new directors of the company is former Gov. Sean Parnell.

Redoubt and West McArthur River

Cook Inlet Energy acquired the Redoubt unit and the West McArthur River unit through the 2009 bankruptcy auction of former operator Pacific Energy Resources Ltd.

For both units, the company typically submits its plans of development in January, which came this year as Miller was reorganizing and Glacier was coming into existence.

Under the 16th plan of development for Redoubt, which runs through March 2017, Cook Inlet Energy proposed a fairly robust program. Assuming that the company emerged from bankruptcy intact — which it did — Cook Inlet Energy said it would sidetrack the existing RU-4A and RU-4B sidetracks by 2018. The company also suggested that it might convert the RU-3 well as a water injector or sidetrack the existing RU-7B sidetrack, depending on economics. The company also proposed a workover program at RU- 1A and RU-9.

According to AOGCC records, Cook Inlet Energy drilled no wells or sidetracks through the development cycle ending March 2016 or through the first nine months of 2016.

Through a workover campaign, Cook Inlet Energy returned the dormant Redoubt unit to production from the Osprey platform in mid-2011 and started drilling sidetracks and wells in 2014. The slowdown in activity since then appears to be impacting production.

By the start of 2014, the Redoubt unit had produced 2.88 million barrels of oil, according to the Alaska Oil and Gas Conservation

continued on page 46

GLACIER *continued from page 45*

Commission, and produced some 400,000 barrels over the course of the year to a cumulative total of 3.28 million by the start of 2015. By this beginning of this year, cumulative production had increased by 350,000 barrels to 3.63 million. Through the first six months of this year, the unit produced 100,000 barrels.

Similarly, Cook Inlet Energy initially focused on working over existing West McArthur River unit wells before expanding to new wells in 2014. In early 2015, the company told state officials it believed sidetracking existing wells was the best strategy for improving production at the field, but those plans have been on hold. This year, Cook Inlet Energy proposed no additional drilling, instead suggesting it would focus on ways to improve recovery from existing wells. The company stuck to its plans, drilling no wells or sidetracks at the unit this year, through September 2016, according to AOGCC records.

As with the Redoubt unit, the lack of activity at West McArthur River appears to be slowing production rates. By the start of 2014, the unit had produced 13.30 million barrels of oil. The unit produced some 500,000 barrels over the course of the year to a cumulative total of 13.8 million by the start of 2015. By this beginning of this year, cumulative production had increased by approximately 470,000 barrels to a total of 14.27 million. Through the first six months of this year, the unit produced 190,000 barrels.

North Fork

Cook Inlet Energy acquired the North Fork unit in late 2013. When global crude oil prices began declining in late 2014, the existing natural gas production (and also the existing sales contract) made the onshore unit particularly valuable to the company.

Cook Inlet Energy submitted its most recent plan of development for the unit in late December 2015, as Miller was in the early stages of its bankruptcy proceedings. The state approved the plan in early March 2016, after those proceedings had been completed.

Cook Inlet Energy completed the North Fork Unit No. 24-26 well in late 2014 and the North Fork Unit No. 42-35 well in early 2015, both of which fell within the timeframe of the existing 49th plan of development running from March 2014 to March 2015. The results of NFU No. 42-35 were "disappointing," according to the company. "These poor results, coupled with an increasingly constrained financial situation, necessitated a pause in drilling activity at the North Fork Unit throughout the 50th Plan Year," Cook Inlet Energy told state officials in its 50th plan of development, filed in December 2015.

In that plan of development, which outlined activities from March 2015 to March 2016, Cook Inlet Energy proposed a three-well development program for North Fork. The company drilled no wells or sidetracks for the remainder of 2015 or the first nine months of 2016, according to AOGCC. The company finished permitting the North Fork Unit No. 14-26 well in August 2015 but had yet to complete the well by September 2016.

In its 51st plan of development, for the year ending March 2017, Cook Inlet Energy again proposed to drill or sidewalk as many as three wells. The company said it would begin by sidetracking the existing North Fork Unit No. 42-35 well or North Fork Unit No. 42-35A sidetrack, followed by drilling the grassroots North Fork Unit No. 14-26 well. If the results of those two wells and sidetracks were favorable, and if economic conditions warranted, the company said it might also consider drilling a second delineation well.

In early 2016, AOGCC approved pool rules for the Tyonek gas pool at North Fork, which Cook Inlet Energy set as a prerequisite for sidetracking the existing North Fork Unit No. 42-35 well. The company intended to complete the project either late in the 50th planning cycle — early 2016 — or early in the next current cycle. Those plans never materialized. Given that the company never sidetracked the NFU No. 42-35, and therefore never got results, the continued halt in drilling is likely economic in nature.

Without any drilling scheduled for 2016, Cook Inlet Energy proposed a year of planning instead. The company proposed improving infrastructure such as compression and separation facilities, monitoring existing wells, planning for future development drilling, evaluating the need for a new pad in the northeast of the participating area and analyzing previous results to determine the value of drilling outside the existing participating area.

By the start of 2014, the North Fork unit had produced 6.18 billion cubic feet of natural gas. The unit produced 3.27 million cubic feet over the course of the year to a cumulative total of 9.45 bcf by the start of 2015. By the beginning of this year, cumulative production had increased by approximately 3.22 million cubic feet to a total of 12.67 bcf. Without continued activity, production is beginning to suffer. Through the first six months of this year, the unit produced 1.26 million cubic feet. If that rate continues for the second half of the year, it would represent a notable slowdown in production.

Badami

Miller acquired Savant Alaska and its 67.5 percent working interest in the Badami unit over the last half of 2014, a period of time when global oil prices fell by more than half.

With the combination of low oil prices and the ongoing bankruptcy proceedings, Savant was "unable to justify the expense" of conducting hydraulic fracture stimulations on two existing wells and drilling two new wells at the unit over this past year, the company told state officials in its most recent plan of development, which was filed in April 2016.

Those projects had been scheduled for late 2014 or early 2015 but were postponed to this past year because the company was unable to secure and barge equipment to Badami in time to complete the activities before the end of the open water season in the Arctic.

Savant now plans to pursue those projects "as economic conditions warrant." The company is currently undergoing internal evaluations to determine what opportunities exist and intended to review those plans with state officials by the end of September.

As part of the reorganization, Savant began 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 is also reviewing potential targets outside the Badami Sands participating area, including the Killian Sands on the eastern end of the unit.

Even with those economic and administrative obstacles preventing development and exploration, Savant managed to improve operations at Badami over the past year.

A "minor workover" of the B1-11A and B1-36 wells 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. Although small by North Slope standards, such an increase is noteworthy for the unit, which has struggled to reach its full production potential since BP brought it online in 1998.

By the start of 2014, the Badami unit had produced 6.65 million barrels of oil. The unit produced 390,000 barrels over the course of the year to reach a cumulative total of 7.04 million by the start of 2015. By the start of this year, cumulative production was 7.38 million barrels, up 340,000 barrels over the year before. Through the first six months of this year, the unit produced 190,000. If production holds steady for the remainder of the year, it would represent an increase over 2015, reflecting the benefits of the workovers. ●

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Hilcorp slows drilling activities in Cook Inlet

After several years of major activities throughout the basin, 2016 is a step back

By ERIC LIDJI
For Petroleum News

Through two expansive acquisitions and two targeted purchases over the past five years, Hilcorp Alaska LLC became the dominant producer in the Cook Inlet region.

The local subsidiary of the Texas-based independent currently operates some 20 units and un-unitized fields in the region. The number occasionally changes as the company consolidates operations. Considered geographically, those holdings can be divided into four informal groups: onshore west side, offshore, northern Kenai and southern Kenai.


DAVE WILKINS

While it is difficult to make a comprehensive assessment about a portfolio of that size, Hilcorp appears to be slowing its drilling and workover activities this year, after several years of considerable efforts to improve or restore production at aging oil and gas fields.

The current period of low oil prices could be partially responsible for any deferred investment at oil fields in the portfolio. Any slowdowns in activity at gas fields could be economic or could suggest that Hilcorp is already meeting current supply commitments.

Onshore west side

Hilcorp operates five onshore units at the northern end of the west side of Cook Inlet: the Ivan River, Lewis River, Pretty Creek and Stump Lake units; and the larger Beluga River unit.

The first four of those are smaller units, with sometimes-spotty production history. In a recent development plan from March 2016, Hilcorp warned that the four small fields risk becoming marginally profitable under current economic and regulatory environment.

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The Ivan River, Lewis River and Pretty Creek units are currently in production, although development activities have slowed in recent years. Hilcorp did not drill any wells or conduct any rig workover operations at the units in 2015 and planned none for 2016.

The Ivan River unit produced some 1.8 million cubic feet per day from the Sterling-Beluga Gas participating area and 1.2 million cubic feet per day from the Tyonek participating area in 2015, according to Hilcorp. By the start of 2014, the unit had produced 84.3 billion cubic feet, according to the Alaska Oil and Gas Conservation Commission. Ivan River produced some 700 million cubic feet that year and 400 million cubic feet in 2015, for a total of 85.4 bcf by the start of this year. The unit produced 200 million cubic feet in the first six months of this year — on pace with 2015 production.

A previous operator established a gas storage operation at the unit in 2011 but Hilcorp relinquished the storage lease last year because of damage to the IRU 44-36 well.

The Lewis River unit currently produces from one well. Hilcorp suspended a disposal well at the unit in 2015. By the start of 2014, the unit had produced 14.39 billion cubic feet, according to the AOGCC. The unit produced some 427 million cubic feet that year and 336 million cubic feet in 2015, for a cumulative total of 15.15 bcf by the start of this year. The unit produced approximately 89 million cubic feet during the first six months of this year, which suggests a notable decline from 2015 production levels.

The Pretty Creek unit produced some 300,000 cubic feet from the Beluga participating area in 2015. The unit includes a storage operation. Hilcorp injected 291 million cubic feet and withdrew 528 million cubic feet during 2015. The storage program complicates production reporting for the unit. According to AOGCC records, cumulative production "declined" from 9.54 billion cubic feet at the start of 2014 to 9.51 bcf at the end of June 2016, which suggests a balance of injection and withdrawals from the unit.

A previous operator suspended the Stump Lake unit shortly after gas production started in 1977. The unit produced from the 41-33 well from 1990 until 2000 and again from 2009 until 2012, when mechanical issues from a workover compromised production. The suspended unit had cumulatively produced some 6.6 billion cubic feet through June 2016.

A state-mandated program to swab the 41-33 well and add perforations if the swabbing failed to restore production failed to restore production. Hilcorp said it would study the feasibility of drilling a new well or conducting a rig workover to fix the problems with 41-33. If the company chose to go in that direction, the program would have to occur in winter to meet seasonal restriction in the surrounding Susitna Flats State Game Refuge.

Another possibility is to connect the Stump Lake unit to the Beluga River unit. "Hilcorp's increased presence on the west side of Cook Inlet brings new opportunities to make rigs, equipment and manpower available to small-scale operations, such as the Stump Lake unit, that otherwise would not be economic," the company told the state in a plan of development from March 2016. Without such "critical mass" of projects in the region, "the economic life of the Stump Lake unit has likely passed," the company added.

While the loss of the Stump Lake unit would have little impact on the overall health of the Cook Inlet region, Hilcorp believes that the state of the small, marginal unit might be a sign of the times. Any development project at Stump Lake would "require substantial fiscal investment with declining economic returns. This situation will eventually spread to other legacy fields throughout Cook Inlet," the company wrote. Hilcorp also urged state officials "to evaluate regulatory and policy changes that, going forward, will extend the useful life of similarly situated legacy fields while minimizing waste, maximizing existing infra-

continued on page 50

COURTESY HILCORP

HILCORP *continued from page 49*

structure and promoting sound environmental and economic policy."

Earlier this year, Hilcorp became operator of the Beluga River unit after ConocoPhillips Alaska Inc. sold its one-third working interest to Municipal Light & Power and Chugach Electric Association. The unit is historically one of the most important in the region, providing fuel that generates much of the electrical power used in the Anchorage area.

Beluga River is also one of the oldest fields in the region. When ConocoPhillips filed the 53rd plan of development for the unit in May 2015, it called the legacy field "fully delineated," suggesting that drilling more wells would fail to yield a worthwhile increase in production rates. The Sterling reservoir had declined to 25 percent of its original pressure, down from 30 percent a year earlier, and deliverability had also declined. There were no new wells drilled at the unit in 2014, 2015 or the first nine months of 2016.

By the start of 2014, the unit had produced 1.272 trillion cubic feet, according to the AOGCC. The unit produced some 25.2 billion cubic feet that year and 21.2 bcf over 2015, for a total of 1.319 trillion by the start of this year. The unit produced 9.3 bcf in the first six months of this year, which suggests a decline from 2015.

With its first plan as operator, Hilcorp proposed a light workload. The company told federal officials it would "conduct routine repairs and replacement of facilities as needed or required to maintain and increase field production." The potential projects on the docket included small pipeline work, expansions to existing production facilities and the installation of additional disposal, injection or processing equipment "where necessary."

Even with the declines, the two utilities expect Beluga River production to remain robust enough to meet a significant portion of their natural gas demand over the next decade.

COURTESY HILCORP

Offshore

Having acquired several neighboring fields previously owned by multiple companies, Hilcorp has been able to simplify its administrative work by consolidating operations.

Those efforts at consolidations have been most prominent among three offshore clusters: the Granite Point unit, the Trading Bay unit and the Middle Ground Shoal unit. When Hilcorp arrived in Alaska, those three clusters were really seven or eight separate fields.

All three areas contribute both oil and gas to the regional grid and at all three areas Hilcorp is offering a dour outlook for investment under the current economic climate.

After several years of working over existing wells at the two fields, Hilcorp recently merged the Granite Point field into the nearby South Granite Point unit to create the Granite Point unit with two participating areas: Hemlock and Granite Point Sands. The consolidated unit includes three legacy platforms: Granite Point, Anna and Bruce.

In a proposed plan of development submitted in March 2016, Hilcorp told state officials it would maintain existing production rates but was limiting its maintenance program to a single workover project to address complications from a previous workover project at the Anna platform. "Under the present economic climate and limited gas market, Hilcorp does not anticipate any new grassroots or sidetrack drilling projects," the company wrote.

Hilcorp drilled one sidetrack in 2014 — the Granite Point State No. 18742 17A well — but drilled no wells or sidetracks in 2015 and none in the first nine months of 2016.

By the start of 2014, Granite Point had produced 149.5 million barrels of oil, according to the AOGCC. The unit produced some 1 million barrels that year and 900,000 barrels in 2015 for a total of 151.4 million at the start of the year. The unit produced some 500,000 barrels in the first six months of 2016, which suggests a slight increase from 2015.

By the start of 2014, Granite Point had produced 133.98 billion cubic feet of gas. The unit produced 796 million cubic feet that year and 804 million cubic feet in 2015 for a total of 135.58 bcf at the start of this year. The unit produced some 390 million cubic feet in the first six months of 2016, which suggests a slight decrease from 2015.

To the south, Hilcorp operates the Trading Bay unit, the McArthur River field to its south and the North Trading Bay unit to its north. Those three fields are currently distinct entities, although Hilcorp provides a single plan of development for all three and has expressed an interest in someday merging the Trading Bay and North Trading Bay units.

Hilcorp told the state to expect an "overall decrease" in development at Trading Bay and McArthur River for 2016 because of "the current economic climate and limited market for gas." The company proposed four sidetracks at McArthur River, and three drilling projects and four workovers at Trading Bay. Trading Bay and McArthur River are home to the Grayling, Dolly Varden, Steelhead, King Salmon and Monopod platforms.

According to the AOGCC, Hilcorp completed the Trading Bay Unit M-34 and A31 wells at McArthur River and Trading Bay, respectively, in 2014, no wells at either field last year, and the Trading Bay State A-27RD2 oil well at McArthur River in late June 2016.

By the start of 2014, the Trading Bay unit had produced 104 million barrels of oil. The unit produced some 1.04 million barrels that year and 1.1 million barrels in 2015, for a total of 106.1 million barrels at the start of this year. The unit produced 434,568 barrels in the first six months of 2016, suggesting a decline from 2015 production levels.

For gas, Trading Bay had produced some 80.2 billion cubic feet by the start of 2014. The unit produced 1.74 billion cubic feet that year and 1.88 bcf in 2015, for a total of 83.8 bcf by the start of this year. The unit produced 654.3 million cubic feet in the first six months of 2016, suggesting a decline from 2015 production levels.

By the start of 2014, McArthur River had produced 635.6 million barrels of oil. The field produced 1.77 million barrels that year and 2.03 million barrels in 2015, for a total of 639.4 million barrels by the start of this year. The field produced 887,455 barrels in the first six months of 2016, which suggests a decline from 2015 production levels.

For gas, McArthur River had produced 1.462 trillion cubic feet by the start of 2014. The field produced 13.3 billion cubic feet that year and 10.5 bcf in 2015, for a total of 1.486 trillion cubic feet by the start of 2016. The field produced 4.5 bcf in the first six months of 2016, which suggests a decline from 2015 production.

The economic climate is also jeopardizing plans at North Trading Bay, where the Spark and Spurr platforms have been lighthoused since in 1992 (aside from a brief attempt at reviving gas production from Spark in 2007). While a previous operator wanted to decommission the platforms as early as 2009, Hilcorp has generally been more hopeful.

This year, Hilcorp told the state, "It is not economically viable or technically feasible to return either platform to production" this year. But Hilcorp still sees possibilities for the platforms. "This alternative remains preferable to abandonment," the company said.

A range of engineering studies planned for 2016 and 2017 should provide some guidance on how best to preserve the platforms. An alternative proposal would "return the North Trading Bay Unit to production via directional wells drilled from the Monopod Platform and drilling/sidetracks from existing platforms," according to the plan of development.

After acquiring the Middle Ground Shoal field and its active "A" and "C" platforms from XTO Energy Inc. in 2015, Hilcorp began consolidating the field with its previously acquired North Middle Ground Shoal field and its shut-in Baker platform to the north and its South Middle Ground Shoal unit and lighthoused Dillon platform to the south.

As Producers was going to print, the state was considering a proposal from Hilcorp to merge the two northern fields into the existing South Middle Ground Shoal unit, and the AOGCC was considering a similar proposal to create new pool rules for the larger unit.

The situation at the Middle Ground Shoal fields is slightly brighter than other offshore properties. Pending "a rebounding economic climate and available gas supply market," Hilcorp plans to reactive the Baker platform in 2017 and might revive the Dillon platform in 2018, the company told state officials in its most recent plan of development. The company is evaluating "intermediate opportunities" to use directional wells from the A and C platforms "to target oil prospects otherwise accessible only from the Baker and Dillon platforms."

By the start of 2014, the Middle Ground Shoal fields had produced 200.9 million barrels of oil. The fields produced some 679,428 barrels that year and 691,986 barrels in 2015, for a total of 202.3 million barrels by the start of this year. The fields produced 343,446 barrels in the first six months of 2016, which suggests an increase from 2015. For gas, Middle Ground Shoal had produced 110.97 billion cubic feet by the start of 2014. The fields produced some 368.2 million cubic feet that year and 198.3 million cubic feet in 2015, for a total of 111.54 bcf by the start of this year. The

continued on page 52

HILCORP *continued from page 51*

fields produced 76.8 million cubic feet in the first six months of 2016, which suggests a decline.

With several maintenance projects, Hilcorp expects production rates to remain steady this year from the two Middle Ground Shoal platforms, but a larger investment program at Platform C is "not feasible under current economic conditions" and might force the company to temporary suspend production sometime this year, the company has said.

Northern Kenai

Hilcorp operates five federal units and one state unit at the northern end of the Kenai Peninsula: Birch Hill, Swanson River, Beaver Creek, Sterling, Cannery Loop and Kenai.

The Birch Hill unit is currently offline, although plans have been in the works for several years to revive production. Hilcorp prepared preliminary engineering plans in 2012 and 2013 and made a site visit to the Birch Hill pad with federal officials in April 2014.

In its 50th plan of development for Birch Hill filed with the U.S. Bureau of Land Management in March 2015, Hilcorp said it would test an existing Birch Hill well this past winter, if weather and the market accommodated. If the test was successful, Hilcorp said it would eventually build surface facilities and install a natural gas gathering line.

Those plans never came to fruition this year. The company is now extending the project into its current plan of development, with operations planned for the second quarter of 2017. As before, the project depends on the weather supporting snow road construction.

If the well proves to be commercial, Hilcorp expects three-to-six months of planning, design and permitting facilities and an additional three months of actual construction.

As of June 2016, cumulative production at Birch Hill was 65.3 million cubic feet.

To the south of Birch Hill is the Swanson River oil field, which was discovered in 1957.

After Hilcorp arrived in Alaska, the Swanson River oil field became a model for how the company would approach the aging fields in its newly acquired Cook Inlet portfolio: a drilling campaign combined with a thorough effort to sidetrack or repair existing wells.

Through 2012 and 2013, Hilcorp drilled at least eight wells and undertook a major workover campaign, which yielded a noticeable increase in oil production rates.

The pace of activities has slowed since then. Hilcorp drilled four wells and one sidetrack in 2014, two wells and one sidetrack in 2015, and two sidetracks through the first nine months of 2016, according to AOGCC records. While those figures suggest a continual decline, the drilling dates tell a different story. Hilcorp brought a sidetrack online in February 2015, brought two wells online in October 2015 and completed two sidetracks during February and March 2016. The wells in the 2014 program were evenly spaced.

That said, Hilcorp told the state that it had no plans to drill any wells or sidetracks at Swanson River under its current plan of development, which runs from April 2016 to March 2017. The company planned to work over the SCU 33-33 and SCU 44-33 wells during this cycle, and could potentially add two more projects to the list. The company only performed one workover project — on the SCU 12B-09 well — during the previous cycle.

The slowdown in drilling might have impacted production. The unit was producing 3,600 barrels of oil equivalent per day at the start of 2015 and 3,250 barrels of oil equivalent per day by the end of the year, according to figures Hilcorp included in its development plan.

That said, cumulative production has been increasing from year to year.

By the start of 2014, Swanson River had produced 231.2 cumulative million barrels of oil. The unit produced some 800,000 barrels that year and 1 million barrels in 2015, for a total of 233 million by the start of this year. The unit produced 900,000 barrels in the first six months of 2016, which suggests a large increase from 2015. Swanson River is also seeing increased gas production. By the start of 2014, the unit had produced 2.919 trillion cubic feet of gas. The unit produced 2.89 million cubic feet that year and 3.88 million cubic feet in 2015, for a total of 2.926 trillion by the start of this year. The unit produced 2.21 million cubic feet in the first six months of 2016, suggesting an increase over 2015.

Like Swanson River, the Beaver Creek unit to the south is one of the older fields in Cook Inlet, with a gas field discovered in 1967 and an associated oil field discovered in 1972.

Hilcorp drilled four wells and three sidetracks at the unit in 2014, but drilled no wells or sidetracks in 2015 or through the first nine months of 2016. The company performed work on eight wells in 2014, two wells in 2015 and proposed work on one well for the current year. Recent activities at the unit have been focused on upgrading facilities.

As part of its efforts to optimize the unit, Hilcorp sought AOGCC approval to expand the description of the Beluga gas pool and to create a new gas pool in the Tyonek. The company said that it discovered the Tyonek accumulation through its recent activities.

Today, oil production at Beaver Creek is small. By the start of 2014, the unit had produced 6.22 million barrels, according to the AOGCC. The unit produced some 40,000 barrels that year and 50,000 barrels in 2015 to reach 6.31 million by the start of this year. In the first six months of 2016, the unit produced 20,000 barrels, suggesting a decline.

With natural gas production, Hilcorp saw quick results from its large development program. By the start of 2014, Beaver Creek had produced 215 billion cubic feet. The unit produced 4.45 million cubic feet that year and 6.26 million cubic feet in 2015 for a total of 227 bcf by the start of this year. In the first six months of 2016, the unit produced 2.25 million cubic feet, which suggests a decline over 2015 production.

While the Swanson River and Beaver Creek units have been steadfast producers for decades, the equally old Sterling unit to the south has been less reliable throughout its long history. The field was discovered in the early 1960s, with additional intervals discovered in the late 1990s, but production has been spotty. At times, operators have suspended individual intervals, entire pools and even the whole unit for stretches.

As with the Birch Hill unit, Hilcorp has recently been looking for ways to extend the life of the Sterling unit. The most likely option is a future workover campaign.

As has been the case in the past, production is currently sporadic. By the start of 2014, Sterling had produced 14.3 billion cubic feet. The unit produced 139 million cubic feet that year but only 86,000 cubic feet in 2015 and none in the first six months of 2016.

The Kenai unit to the southwest was the first major gas discovery in Cook Inlet, discovered in 1959 and brought online two years later with a pipeline to Anchorage.

The unit continues to remain an important source of gas supplies and continues to receive considerable investment, even several years into Hilcorp ownership of the property.

Hilcorp drilled six wells at the unit in 2014 and three in 2015. In its most recent plan of development, the company proposed a six-well development program split between the Tyonek pool and the Beluga/Upper Tyonek pool for this year. The company had not completed any wells at the unit in the first six months of 2016, according to the AOGCC.

Hilcorp performed work on seven existing wells in 2015. The company proposed a major workover campaign for this year, including as many as 10 coil tubing workovers, as many as five rig workovers and as many as 10 E-line recompletes. The company also suggested it might expand pads and facilities and increase compression this year.

By the start of 2014, the Kenai unit had produced 2.416 trillion cubic feet. The unit produced 19.2 billion cubic feet that year and 22.8 bcf in 2015 for a total of 2.466 trillion cubic feet by the start of this year. In the first six months of 2016, the unit produced 8.4 bcf, which suggests a steep decline over 2015 production.

Cannery Loop is a state-managed unit immediately north of Kenai. Although it began its life as a producing gas field, it has become more important as a regional storage facility.

Hilcorp drilled no wells at the unit in 2014, one well in 2015 and one well in the first six months of 2016. The company started drilling the 2016 well at the end of 2015 and proposed no additional drilling at the unit this year. The company performed no workovers in 2014, two workovers in 2015 and proposed two workovers for 2016.

By the start of 2016, the two most recent wells — CLU No. 13 and CLU No. 5RD — but produced approximately 2.25 million cubic feet per day, according to Hilcorp. The company forecast declining production this year as CLU No. 5RD depleted followed an increased production as the next zone in the well was completed through a workover.

Those increases appear to be occurring.

By the start of 2014, Cannery Loop had produced 187.8 billion cubic feet. The unit produced 3.58 bcf that year and 2.43 bcf in 2015 for a total of 193.9 bcf at the start of this year. In the first six months of 2016, the unit produced 2.68 bcf, which suggests a considerable increase over 2015.

Southern Kenai

At the other end of the peninsula, Hilcorp operates four units: the offshore Kasilof unit, the coastal Ninilchik unit, the onshore Deep Creek unit and the onshore Nikolaevsk unit.

Earlier this year, Hilcorp announced plans to relinquish the Kasilof unit. The decision followed several years where the company suspended operations while it tried to decide whether to return the two-lease unit to regular operation, use the facilities to assist with operations at the nearby Ninilchik unit or permanently discontinue Kasilof operations.

The Kasilof unit produced 4.32 billion cubic feet of gas through June 2016.

The recent programs Hilcorp has undertaken at the Ninilchik and Deep Creek units have occasionally been classified as exploratory, even when work occurred inside the units.

The Ninilchik unit follows the coastline in the area south of Kasilof in the southern Kenai Peninsula. Onshore pads are used to reach offshore targets with directional wells.

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After acquiring the unit in 2013, Hilcorp proposed drilling exploration wells from existing drilling pads and building several additional pads in under-developed areas.

The unit currently has nine pads (from north to south): Abalone, Falls Creek, Bartolowits, Blossom, Grassim Oskoloff, Ninilchik State, Susan Dionne and Paxton. The ninth is the Kalotsa pad, which the state approved as The Producers was going to press.

Hilcorp drilled at least five wells and sidetracks at the Ninilchik unit in 2014 and four more in 2015, according to AOGCC records. The company intended to drill the Kalotsa No. 1 well in 2015, but "permitting issues" delayed construction of the Kalotsa pad and pushed the project in 2016. The company also intended to drill the Grassim Oskoloff No. 9 well this year, although the well had yet to be permitted as of September 2016.

By the start of 2014, Ninilchik had produced 149.85 billion cubic feet of gas, according to the AOGCC. The unit produced some 13.68 bcf that year and 13.95 bcf in 2015 for a total of 177.5 bcf by the start of this year. The unit produced 6.26 bcf in the first six months of 2016, which suggests a decline.

All existing developments at the Deep Creek unit are clustered in the Happy Valley participating area, in the northern end of the unit. The state and landowner Cook Inlet Region Inc. believe the southern half could also contain considerable resources and were ready to contract the acreage when Hilcorp acquired the property in early 2012.

Even though Hilcorp has yet to drill at the Middle Happy Valley prospect in the southern end of the unit, its exploration efforts in the northern end convinced the state to repeatedly defer contraction. The state approved a plan of operations for the project in

continued on page 55

Hilcorp working slowly and steadily on the North Slope

Operations to date have focused largely on reviving and improving Milne Point

By ERIC LIDJI
For Petroleum News


COURTESY HILCORP

When Hilcorp Alaska LLC expanded its operations to include a package of North Slope properties, the company intended to develop the Arctic the same way it had been developing Cook Inlet: reducing operating costs, revitalizing fields on a nearly well-by-well basis and drilling wells in and around existing units when opportunities existed.

The local subsidiary of the Texas-based independent has started that process. And while the company was expecting the Arctic to be a costlier and more difficult place to operate, a period of low oil prices has preventing the company from seeing the gains it expected.

"We have a long ways to go before we're coming anywhere close to making the money that we hoped to make when we originally made that investment a year and a half ago," Hilcorp Energy Co. President Greg Lalicker said at the Resource Development Council's annual conference in mid-November 2015. And while the company was working on the problem, he added, it wasn't expecting an increase in oil prices to come to the rescue.

After months of negotiations, Hilcorp closed on its acquisition on four BP Exploration (Alaska) Inc. properties on the North Slope in late 2014. Through the deal, Hilcorp became owner and operator of the Northstar unit, operator and majority owner of the Duck Island unit, the operator and 50 percent working interest owner of the Milne Point unit and a 50 percent working interest owner of the offshore BP-operated Liberty field.

Milne Point

Aside from working with BP on federal permitting activities at Liberty, most of Hilcorp's resources on the North Slope since the acquisition have gone toward the Milne Point unit.

Hilcorp believes Milne Point contains considerable resources, from light oil in deep reservoir rocks to heavy oil in the shallower Ugnu formation. But accessing those resources is a slow and steady process, according to Lalicker. "It isn't one big project that makes this happen," he told lawmakers at an informal meeting in February 2016. "It's lots of little things all the time. That's what you do with properties late in their life."

So far, the Milne Point program has been diverse. Hilcorp has expanded infrastructure, proposed administrative changes, repaired existing wells and begun drilling new wells.

Over the course of 2015, working under an existing BP plan of development, Hilcorp brought five wells back into operation but nevertheless saw a slight decline in total unit production, which the company blamed on a large backlog of workovers to complete.

Under its current plan of development, which runs through the end of July 2017, Hilcorp proposed drilling eight new wells at five pads targeting three of the four formations present at the unit, conducting workover operations on as many as 16 existing wells, potentially undertaking a new Moose Pad Development Project at the western end of the unit and expanding other unit infrastructure to accommodate increased oil production.

BP drilled seven wells at Milne Point in 2014, although many of those were multilateral wells, accounting for 14 penetrations altogether. While Hilcorp drilled only three wells at the unit in 2015, it had already drilled eight wells through the first nine months of 2016.

Comparing those programs shows some of the differences between the companies. Aside from a single well at L pad, the BP drilling program in 2014 occurred exclusively at F pad. So far, the Hilcorp program in 2015 and 2016 has been more diverse. The 11 wells included four at L pad, three at J pad, two at B pad, one at K pad and one at C pad. While BP exclusively targeted the Kuparuk formation, Hilcorp was primarily targeting the

continued on page 55

HILCORP INLET *continued from page 53*

late 2015. Hilcorp deferred the program several months later, citing permitting delays.

In its most recent plan of development, filed in March 2016, the company wrote, "Hilcorp remains committed to building the road and pad required to drill the Middle Happy Valley well, but cannot commit to drilling this exploratory prospect under the current economic and market climate." Instead, Hilcorp said it would commission a 2-D seismic survey in the southern end of the unit. Combined with existing 3-D seismic, the survey could allow Hilcorp identify other opportunities in the southern end of the unit.

With the Middle Happy Valley project on hold, Hilcorp instead spud the Happy Valley B-17 development well in late November 2015. The directional well started within the participating area but extended beyond its northern boundary. The company completed the well in May 2016, according to AOGCC records. The company said it might drill a B-18 well to further delineate the region, if the B-17 well proved to be commercial.

By the start of 2014, Deep Creek had produced 24.53 billion cubic feet of gas, according to the AOGCC. The unit produced some 3.2 bcf that year and 2.43 bcf in 2015 for a total of 30.17 bcf by the start of this year. The unit produced some 1 bcf in the first six months of 2016, which suggests a decline.

Farther south, Hilcorp also operates the tiny Nikolaevsk unit.

The project was one of the earliest victories for Hilcorp in Alaska. A previous operator discovered natural gas in 2004 but delayed development because of the distance from existing infrastructure in the region. Shortly after acquiring the prospect, Hilcorp commissioned a pipeline to connect the unit to the existing regional transmission grid.

After bringing the unit into production, activities have slowed considerably. Hilcorp performed no drilling or major well work activity at the unit in 2014 or 2015 and planned no activities for 2016, calling the exploration and development potential "limited."

By the start of 2014, Nikolaevsk had produced 479.1 million cubic feet of gas, according to the AOGCC. The unit produced some 171 million cubic feet that year and 80.8 million cubic feet in 2015 for a total of 731.8 million by the start of this year. The unit produced 18.5 million cubic feet in the first six months of 2016, which suggests a decline. ●

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HILCORP NORTH SLOPE *continued from page 53*

Schrader Bluff formation (aside from a single Kuparuk well at K pad and a single Sag River well at C Pad). Also, the BP program was mostly a collection of laterals and sidetracks of existing well while the Hilcorp program has been exclusively single wells.

Finally, while BP often used new technological applications to improve production, Hilcorp seems to prefer maintenance activities. Hilcorp only completed three wells at Milne Point in 2015 but conducted workover operations on 54 existing wells — 29 in the Kuparuk formation, 23 in the Schrader Bluff formation and two in the Ugnu formation.

In addition to working over and drilling wells, a large portion of the Milne Point program this year focused on administrative and infrastructure programs. One example is a series of permitting projects to improve injection at the unit by expanding the physical boundary of the unit, modifying an existing underground injection control Class I permit, building a Milne Point Unit Grind and Inject Facility at the pad to accommodate 40,000 cubic yards of materials each year and expanding the associated Milne Point B pad.

Also in 2016, Hilcorp asked the state for permission to add some 1.66 acres to existing L pad to accommodate a proposed five-well development program and to add some 1.59 acres to E pad to accommodate a proposed eight-well development program.

By the start of 2014, BP had produced 314.8 million barrels of oil at Milne Point, according to the Alaska Oil and Gas Conservation Commission. The unit produced 7.1 million barrels over that year, for a cumulative total of 321.9 million by the start of 2015.

With Hilcorp as operator, production declined to 6.8 million barrels in 2015, for a total of 328.7 million by the start of this year. In the first six months of 2016, the unit produced 3.5 million. If that rate continues for the second half of the year, Milne Point would produce slightly more this year than last year and slightly less than it produced in 2014.

Duck Island, Northstar, Liberty

The programs at the Duck Island and Northstar units remain at an earlier stage.

At both units, Hilcorp has been working over existing wells. The company drilled no new wells or sidetracks at either unit in 2015 and has no plans to do so this year, either.

Hilcorp conducted 11 workover projects at Duck Island between July 2015 and April 2016 and five workover projects at the Northstar unit over the same time. The company is proposing five projects at Duck Island and three at North Star over the coming year.

By the start of 2014, the Duck Island unit had produced 476.4 million barrels of oil, according to the AOGCC. The unit produced 2.7 million barrels of oil that year, for a cumulative total of 479.1 million by the start of 2015. Production declined slightly in 2015, to 2.5 million barrels for the year and a cumulative total of 481.6 million by the start of this year. In the first six months of 2016, the unit produced 1.3 million barrels.

Cumulative production at the Northstar unit was 159.6 million barrels by the start of 2014, according to the AOGCC. The unit produced 3.2 million barrels that year for a total of 162.8 million by the start of 2015. Annual productions declined to 2.2 million barrels in 2015, for a total of 165 million by the start of this year. The unit produced 1 million barrels in the first six months of this year, suggestion a slowdown in the decline rate.

The Liberty project remains in the permitting stage.

After cancelling an earlier proposal for the field, BP handed the reins of the project over to Hilcorp, which filed a new development proposal with regulations in late 2014.

The U.S. Bureau of Ocean Energy Management officially began reviewing the new proposal in mid-September 2015 and twice extended a public commenting deadline on the initial scoping portion of the environmental review. Under the Hilcorp proposal, the companies would develop the Liberty field from a new gravel island in the Beaufort Sea. ●

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Barrow gas fields remain steady

The three fields supplying Barrow have been reliable since recent expansion

By ERIC LIDJI
For Petroleum News

The angst ringing through the Alaska oil patch is barely heard at the Barrow gas fields.

The South Barrow, East Barrow and Walakpa fields have been providing fuel for the city of Barrow for decades. A pair of voter-approved bond sales allowed the city to launch a $92 million program in 2011, which further bolstered the fields for the future. The city commissioned the Savik 1 and 2 wells at East Barrow and the Walakpa 11, 12, and 13 wells at Walakpa — the first horizontal drilling campaign ever conducted at the fields.

By improving deliverability, Barrow has been able to use natural gas for its energy needs even during cold snaps or maintenance activities, instead of falling back on diesel fuel.

South and East 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 and drilling continued for decades, with 13 new wells drilled and one 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 demand during peak winter months, which has does not appear to have been necessary for the past few years.

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

The U.S. Geological Survey discovered the East Barrow field with the South Barrow No. 12 well in 1974, during the second wave of NPR-A exploration. Production began in December 1981, but drilling continued through 1990, with eight wells altogether. East Barrow production peaked at some 2.75 million cubic feet per day in early 1984.

At the start of 2014, the East Barrow field had produced more than 8.8 bcf of natural gas, according to the Alaska Oil and Gas Conservation Commission. By the start of 2015, production was more than 8.9 bcf. At the start of 2016, cumulative production had increased by some 200 million cubic feet to more than 9.1 bcf, where it more or less remained through the first six months of this year, as temperatures rose.

That figure greatly surpasses an early estimate of 6.2 bcf in place.

The city of Barrow attributes the productivity of East Barrow to methane hydrates — molecules of natural gas trapped inside cages of ice. The gas can be released through pressure changes. Drops in pressure occur naturally during the aging process of a field.

Walakpa

The South Barrow and East Barrow reservoirs are in a stratigraphic setting similar to the Alpine oil field some 135 miles to the east. The third field supplying the city of Barrow, Walakpa, is in the Pebble Shale unit, a major North Slope petroleum source rock.

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

Working under a Navy contract, Husky Oil discovered Walakpa 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.

At the start of 2014, the Walakpa field had produced more than 25.5 bcf of gas. At the start of 2015, cumulative production had increased approximately 1.4 bcf to more than 26.9 bcf. By the start of this year, cumulative production had increased approximately 1.4 bcf to a total of more than 28.3 bcf. In the first half of 2016, Walakpa produced 800 million cubic feet, suggesting steady rates. ●

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