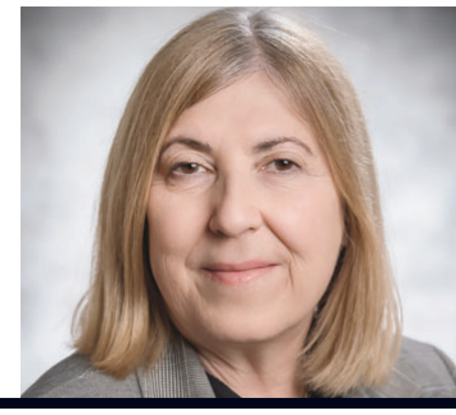
Petroleum news



page 3 EIA forecasts steady Brent in low $60s, US crude production growth

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ConocoPhillips sets drilling records

ConocoPhillips Alaska has set North American and Alaska drilling records at the CD5 drill site in the Colville River unit. The company said April 10 that its CD5-25 well set the North American land-based well drilling record for the longest horizontal lateral, 21,748 feet. The well was drilled by Doyon Rig 19.

The well has a true vertical depth of some 7,900 feet and the record-setting lateral was drilled in the Alpine A sand.

The company also set two state of Alaska records at the well: for total combined lateral length and total combined footage for a well. The combined length of the two laterals, in the Alpine A sand and Alpine C sand, was 34,211 feet. The total combined footage for the well was a state record at 42,993 feet, the company said.

"Improved technology like extended reach drilling and multilateral wells allow ConocoPhillips to maximize production while

see **DRILLING RECORDS** *page 11*

Icewine 3-D completed in March

88 Energy Ltd. said April 6 that its Icewine 3-D seismic survey was completed March 28, as was a second survey, over the Yukon Gold acreage the company acquired last year. The company said processing of data from initial areas of the Icewine acquisition has begun and some early products will be available in June.

The Icewine 3-D survey was designed to confirm leads identified in existing 2-D seismic and covered conventional targets on the western margin of the company's North Slope acreage. Geokinetics Inc. was the contractor for the Icewine survey; that application was approved by the state in January.

88 Energy said plans for a farm-out ahead of the 2019 drilling season are underway, with the formal process expected to begin mid-year.

see **ICEWINE 3-D** *page 10*

IGU in pursuit of new gas supply

On April 9, during a board meeting called at short notice, the board of the Interior Gas Utility passed a resolution authorizing Jomo Stewart, IGU general manager, to finalize the terms of a new gas supply contract for the utility. Neither IGU nor the board is disclosing either the identity of the gas supplier or the terms of the proposed contract. The board would need to approve the new contract before it can go into effect.

According to the April 9 resolution, IGU began negotiations with the supplier on March 31 and has agreed terms for the new supply "at an appreciably lower price and for an appreciably longer term, to succeed currently contracted volumes."

As part of the Alaska Industrial Development and Export Authority's Interior Energy Project, IGU is in the process of purchasing Pentex Alaska Natural Gas Co, with the purchase expected to complete by late May. Pentex owns gas utility Fairbanks

see **GAS SUPPLY** *page 10*

Bonding bills move to Finance

The bills proposed by the administration to bond for payment of oil tax credits, allowing them to be paid off quickly, have progressed through the Resources Committee in both House and Senate. House Bill 331 was awaiting transmittal to the next committee (House Finance) when this issue of Petroleum News went to press; Senate Bill 176 was in Senate Finance, but no hearing had been scheduled.

There was considerable committee discussion, including what companies should have expected and whether bonding for this was constitutional.

Rep. John Lincoln, D-Kotzebue, asked in House Resources how reasonable it was for exploration companies to have thought the credits would be paid.

see **BONDING BILLS** *page 8*

UTILITIES

The debate continues

House Energy hears further testimony on reform of Railbelt electrical system

By ALAN BAILEY

Petroleum News

On April 5 the House Special Committee on Energy heard further testimony on issues surrounding efforts to adopt a more unified approach to the management and operation of the electricity supply system that serves consumers in the Alaska Railbelt. As reported previously in Petroleum News, the committee is considering House Bill 382, introduced by committee chair Rep. Adam Wool, D-Fairbanks, that would mandate the formation of a Railbelt Electrical System Authority for overseeing the system.

Currently the fragmented management of the system, with six independent utilities owning and operating different sectors, leads to inefficiencies in the manner in which the system operates. The belief is that, through a more unified management approach under some form of unified system operator, the cost of electricity for consumers could be reduced without sacrificing supply reliability. Proponents of renewable

> *Julie Estey, director of external affairs for Matanuska Electric Association, said that MEA opposes HB 382 and would prefer to continue with the utilities' voluntary efforts that, she said, are making progress.*

see **POWER DEBATE** *page 7*

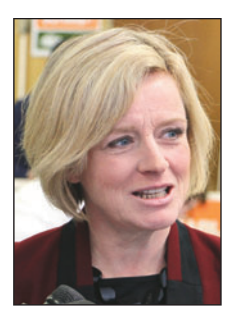
PIPELINES & DOWNSTREAM

Pipeline in crisis

Kinder Morgan suspends Trans Mountain work; sets deadline for governments

By GARY PARK

For Petroleum News



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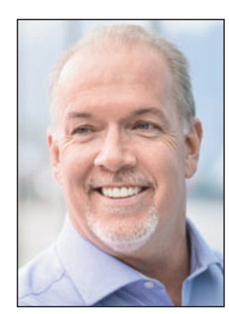

JOHN HORGAN

In a stunning move, Kinder Morgan has suspended all "non-essential" work on its Trans Mountain pipeline expansion in Canada, effectively setting May 31 as a "make-or-break" deadline for its future in the C$7.4 billion project.

Alberta Premier Rachel Notley immediately raised the stakes, declaring that her province will do "whatever it takes to get this pipeline built," including taking an ownership position.

She also promised early legislation that will have "serious economic consequences" for British Columbia, hinting at possibly turning off the flow of crude oil and natural gas to B.C., which she and Kinder Morgan blamed for the fast-emerging test of Canada's national unity.

Notley said the message to British Columbia will be blunt: "Don't mess with Alberta."

Kinder Morgan Chief Executive Officer Steve Kean told analysts April 9 his company was "open" to discussions on having Alberta as a partner.

B.C. Premier John Horgan denied his government has been harassing the plans to triple shipments of

see **TRANS MOUNTAIN** *page 12*

GOVERNMENT

New tax bill introduced

House Finance hears reviews by Revenue, consultant, industry on House Bill 411

By KRISTEN NELSON

Petroleum News

PAUL SEATON

Rep. Paul Seaton, R-Homer, co-chair of the House Finance Committee, provided an overview April 10 of a committee bill introduced April 6 intended to raise production taxes on the oil and gas industry in Alaska.

Seaton told committee members that tax increase provisions in House Bill 411 were almost identical to those contained in HB 111 last year. The portion of that bill which passed the Legislature addressed just the credits issue, he said, not taxes.

Seaton said that worldwide about two-thirds of the wealth from oil and gas production goes to nonproducers, what is referred to as government take. The Alaska metric, he said, has been one-third, one-third and one-third — federal government, state government and producers.

But in Alaska, he said, producers are now taking 48 percent, instead of a third, compared to 37 percent last year.

The state is not getting its fair share of either legacy oil or new oil, he said.

Seaton said HB 411 would repeal the per-barrel credits, lower the production tax rate from 35 percent to 25 percent and establish three additional 5 percent tax brackets — one each at $40 production tax value, $50 PTV and $60 PTV, with the additional

see **HB 411** *page 11*

● EXPLORATION & PRODUCTION

AOGCC approves Meltwater water injection

Commission agrees that production technique change will increase oil production from the ConocoPhillips field in Kuparuk River unit

By ALAN BAILEY
Petroleum News

The Alaska Oil and Gas Conservation Commission has issued an area injection order allowing ConocoPhillips to inject seawater and produced water into the oil reservoir for the Meltwater satellite oil field in the Kuparuk River unit. ConocoPhillips has said, and the commission agrees, that water injection will increase the ultimate recovery of oil from the field.

Currently ConocoPhillips injects natural gas into the reservoir to encourage oil production. However, this has resulted in an increasing gas to oil ratio in the produced fluids. In addition to impacting the oil production at Meltwater, a test performed in 2017 showed that the high ratio has been causing the backing out of 900 barrels per day of production elsewhere in the unit, the commission said in its order.

Meltwater produces from the Bermuda interval in the Seabee formation, a part of the Brookian sequence, the youngest of the North Slope petroleum bearing rock sequence. The Kuparuk River field itself produces from sands within the older Beaufortian sequence. The Bermuda sands at Meltwater have relatively low permeability.

Development history

When production from Meltwater began in 2001 ConocoPhillips used alternating water and gas injection to boost oil production. Initially, miscible injectant, a mixture of natural gas and natural gas liquids, was used for artificial lift in the production wells. However, in 2009 water injection ceased because of corrosion problems in the water line to the field — replacement of the line was deemed unacceptably expensive. Instead ConocoPhillips started using miscible injectant for enhanced oil recovery, a technique which the company said was the best means of maximizing production at that time.

At that point, with ConocoPhillips having no further plans for water injection, water was no longer authorized as an injection fluid for the field.

Indications of leakage

During the period of water injection, ConocoPhillips observed increased pressures in the outer annuli of three wells, but no conclusive reason for this anomaly was determined. However, in 2012 subsurface features identified from seismic data appeared to offer a potential route for miscible injectant to leak into the well outer annuli. ConocoPhillips implemented measures to contain this problem.

In 2015 AOGCC approved the injection of water into the Meltwater reservoir for specific purposes, for surveillance, logging, formation displacements near wellbores and well maintenance.

The miscible injectant used at Meltwater was delivered through a gas line from the Kuparuk River unit Central Processing Facility 2. However, in 2014 ConocoPhillips stopped importing miscible injectant into the Greater Kuparuk Area — at that point gas injection replaced miscible gas injection at Meltwater.

Given the emerging issues arising from continuing gas injection, ConocoPhillips now wants to switch to water injection by converting the gas line to Meltwater, between the Meltwater pad and the Kuparuk 2N pad, for

see MELTWATER INJECTION *page 3*

contents

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● FINANCE & ECONOMY

EIA forecasts Brent at $63 through 2019

WTI expected to average $4 below Brent; US crude forecast at 10.7 million bpd this year, a new record, rising to 11.4 million in 2019

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration's forecast for Brent crude oil spot prices in its April Short-Term Energy Outlook remains roughly the same as the March outlook.

"The short-term outlook continues to forecast that Brent crude oil spot prices will average $63 per barrel in both 2018 and 2019, while West Texas Intermediate will remain below $60 per barrel, averaging about $4 per barrel less than Brent in both years," EIA Administrator Dr. Linda Capuano said in a statement.

The forecast is up slightly from March, when EIA said Brent was expected to average $62 this year and next; the $4 price differential for WTI remains the same. EIA said in the April 10 release that Brent averaged $66 per barrel in March, which is up slightly from the $65 average in April.

The EIA forecasts for Brent compare to a 2017 average of $54 per barrel.

US crude production

"EIA continues to forecast record crude oil production in the United States for both 2018 and 2019, largely as a result of horizontal drilling and hydraulic fracturing in tight rock formations, especially in the Permian region," Capuano said. "April's short-term outlook expects U.S. production to average 10.7 million barrels per day in 2018, which would be a new record and represent an increase of nearly 15 percent from 2017 to 2018."

The 2019 crude oil production forecast is 11.4 million bpd.

The previous record for U.S. production was 9.6 million bpd set in 1970, EIA said.

US natural gas

"U.S. dry natural gas production also remains on pace for record levels in both 2018 and 2019, according to the forecast. This year's production is poised to increase by 7.5 billion cubic feet per day over 2017 levels to an average just above 81 billion cubic feet per day," Capuano said.

LINDA CAPUANO

The 2017 average was 73.6 bcf per day; the 2018 forecast is 81.1 bcf, which would be a new record, the agency said. The 2018 to 2019 increase is projected at 1.7 bcf per day.

"The April short-term outlook maintains the forecast for U.S. natural gas net exports increasing to historic levels in both 2018 and 2019," Capuano said. "U.S. natural gas trade was almost balanced between exports and imports in 2017, but, in this forecast, EIA expects that the United States will see net natural gas exports climb above 4 billion cubic feet per day by 2019 as LNG terminals continue to come online," she said.

The numbers in the EIA forecast are an increase in U.S. natural gas consumption of 4.2 bcf per day, 5.7 percent, this year and 0.7 bcf per day, 0.9 percent, in 2019, led by electric power generation.

Net natural gas exports increased by 0.4 bcf per day in 2017, and the annual average is expected to be 2.2 bcf this year and 4.4 bcf in 2019.

Henry Hub natural gas spot prices are expected to average $2.99 per million British thermal units this year and $3.07 in 2019.

Crude oil markets

EIA said continuing draws on U.S. and global oil inventories combined with actual and potential supply disruptions may have put upward pressure on crude oil prices in March. "Economic and political instability in Venezuela continues to affect its crude oil production," the agency said, with March production averaging 1.5 million bpd, a year-over-year decline of some 24 percent. There is also uncertainty on the U.S. extension of the Joint Comprehensive Plan of Action and without an extension there could be a reinstitution of sanctions on Iran, which could affect that country's oil production and exports.

On the demand side, upward oil price pressures may have been tempered by political issues such as the U.S. and China announcing potential tariffs on several billion dollars' worth of each other's goods. "A slowdown in global trade could affect oil demand and presents downside risks to the global oil consumption forecast," EIA said, noting that the forecast was revised up from the previous outlook, and said it forecasts that global oil consumption will grow by 1.8 million bpd per day both this year and next.

Financials

EIA said fourth-quarter 2017 financials for 46 U.S. oil exploration and production companies "reveal significant effects from the changes to corporate income tax law enacted at the end of 2017," with the producers collectively claiming $7 billion in tax benefits in the quarter.

U.S. companies, the agency said, were also allowed to accelerate depreciation of capital investments made through 2023.

"These two factors could contribute to an increase in investment in upstream production," EIA said.

EIA said capital expenditures for 20 U.S. natural gas producers rose to $4 billion in the fourth quarter, up $1.4 billion from the prior year and the second highest quarterly expenditure in two years.

"Higher revenues and lower costs helped this group of companies report a positive net income in 2017 after two years of losses," the agency said.

Capital expenditures have exceeded cash from operations for the natural gas producers since at least 2013, the agency said, but "the difference narrowed in 2016 and 2017, reducing the need for other types of financing such as issuing debt or equity."

Since 2014 there have been both cost declines and productivity increases, allowing companies to do more with lower expenditures.

EIA said as a result U.S. dry natural gas production was up 3 bcf per day in the fourth quarter of 2017, "the largest quarter-over-quarter increase since 1991." ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 2

MELTWATER INJECTION

the carriage of water.

Can only inject one fluid

In its application to AOGCC for water injection approval, the company said that, with only one functional injection pipeline to the Meltwater pad, only one fluid at a time can be injected into the field reservoir. ConocoPhillips plans to inject water at a lower pressure than was used for the original water and gas injection in the field — maintaining the injection pressure below the fracture pressure of the reservoir and the reservoir overburden helps ensure continued containment of fluids in the reservoir, ConocoPhillips told the commission.

Modeling has indicated that low pressure waterflood will increase ultimate oil recovery by 1 to 2 percent, ConocoPhillips told the commission. Moreover, the potential to recycle injection water through the Meltwater production line can prevent the production line from freezing, as production rates decline. The use of water injection should extend field life by five to 10 years. The AOGCC also commented that the reduction in the produced gas to oil ratio from the use of water rather than gas injection could result in the field reservoir becoming a more appealing target for further drilling.

And, although miscible injectant use is being restored in the Greater Kuparuk Area, to pursue newly drilled targets, the previous injection of miscible injectant into the Meltwater reservoir has rendered further use of the material in the field relatively inefficient in terms of production enhancement.●

Contact Alan Bailey at abailey@petroleumnews.com

● ENVIRONMENT & SAFETY

Spill response in ice laden waters

Some new technologies are addressing the challenges of recovering oil spilled in sea ice conditions in Arctic offshore areas

By ALAN BAILEY
Petroleum News

Responding to an oil spill in ice-laden waters in the Arctic offshore is different from an offshore spill response in warmer climes. And on March 29 during the Alaska Oil Spill Response Symposium Vince Mitchell, Lamor Corp. executive vice president, talked about some new technologies that have been developed for recovering oil from the sea, in situations where sea ice is present. Mitchell and some other speakers at the symposium commented on heightened oil spill risks in the Arctic offshore, as vessel traffic in the region increases.

Mitchell said that although there can be challenges in dealing with ice when responding to an Arctic spill, some features of ice laden waters can work to the responders' advantage: There may be less oil evaporation, less spreading of the oil, and less wave action.

For the non-mechanical recovery of oil, there has been some very promising research into the use of chemical oil herders.

Response strategies

There are three general approaches to dealing with an offshore oil spill: mechanical containment and recovery of the oil; in situ burning of the oil; and the use of oil dispersants. Some combination of these approaches may be required, depending on the circumstances. However, in Arctic conditions a recovery technique must be robust, simple, proven and adaptable to the situation. In-situ burning and dispersant use have associated permitting requirements — mechanical oil recovery appears set to remain a viable option, Mitchell suggested.

Mechanical recovery involves the use of boom for containing an oil slick, and the operation of skimmers, devices that can remove oil from the water for transfer to a holding tank.

Arctic adaptations to mechanical recovery equipment include various arrangements for applying heat, including the use of hot water or steam for heating hoses, double hulled skimmer designs that incorporate heating arrangements; and heated storage tanks, Mitchell said.

For the non-mechanical recovery of oil, there has been some very promising research into the use of chemical oil herders. A herder, added to an oil slick, causes the oil to aggregate thickly, thus making in-situ burning, for example, more efficient.

Tactics in ice

Whereas a spill response in open water typically involves the deployment of long lengths of containment boom, to deflect, concentrate and enable recovery of the oil, the presence of sea ice undermines the practicalities of this approach. As ice concentrations increase, the recovery technique tends more towards the collection of pockets of oil between ice floes. And in heavy ice conditions different techniques and specialized skimmers are required, Mitchell said.

A rope mop skimmer, an oil skimmer with oil attracting material on a chord that cycles through the water, has been the technology of choice for many years for pulling oil from water between ice, Mitchell said. Lamor has developed a vibrating grid arrangement that can separate oil from ice as part of the skimming system. These specialized skimmers are installed on modified oil spill response vessels, Mitchell said.

Lamor also has what is calls an oil recovery bucket, a device that is lowered into the water from a crane and contains a rotating skimmer brush for mopping up the oil. This device, which comes in a variety of sizes, can prove effective in dealing with pockets of oil in broken ice conditions, Mitchell said.

Stern mounted systems

The Finnish Environment Institute has developed what it calls a stern brush, a brush skimmer deployed from the stern of a vessel. The vessel moves slowly astern, using its prop wash to draw oil into the skimmer, Mitchell said.

Lamor has also developed a stern-mounted skimming system called the Sternmax. This has a heating system, a grate that blocks the ice and a hydraulic system for dumping ice off the grate. The device, which can be operated remotely, can break through 1.5 meters of ice, Mitchell said. Highly efficient, oil attracting skimming material minimizes the amount of water recovered along with the oil, thus reducing the amount of water that ends up stored with the recovered oil.

Oil under ice

Recovering oil from under ice presents a particular challenge. A recent project, the Ice Management and Oil Recovery project, used dyes in water to test the efficiencies of different techniques for using skimmers for the recovery of oil trapped under sea ice. Contrary to what might be expected, the research determined that the use of an icebreaker to crush the ice before skimming the oil is not the most effective technique. Instead, it is better to run the vessel onto the ice, down current, to then use a skimmer to draw oil from under the ice. If necessary, it is possible to use the vessel thrusters at low power settings to draw the oil under the ice towards the skimming device. In one test it proved possible to draw dye from a distance of 80 meters from the skimming device in about 20 minutes, Mitchell said.

Other possibilities for future technologies for a cleanup under ice include the use of remotely operated vessels, and the design of skimmers that can function under ice, Mitchell said. ●

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● EXPLORATION & PRODUCTION

Five Cook Inlet development plans approved

Work completed in last plan, proposed for next, described for 2 small Cook Inlet Energy oil fields, 3 small Hilcorp gas fields

By KRISTEN NELSON
Petroleum News

The state has issued approvals for plans of development for five small fields in Cook Inlet, two operated by Glacier Oil's Cook Inlet Energy and three by Hilcorp Alaska.

Companies are required to file PODs for Alaska Department of Natural Resources' Division of Oil and Gas approval annually, outlining plans for the upcoming year and also detailing work done under the previous POD.

The work described illustrates some of what it takes to keep small fields in production.

Cook Inlet Energy PODs

The two Cook Inlet Energy units both produce oil.

Redoubt Shoal is producing 827 barrels per day, division Director Chantal Walsh said in the letter approving the POD, with cumulative production of 4.2 million barrels through November. Redoubt also produces 145,000 cubic feet per day of natural gas, with cumulative production of 2.41 billion cubic feet through November.

In the previous, 17th POD, CIE completed a sidetrack of the RU-3 well and brought it online as a waterflood. The company did not hydraulically fracture two wells, RU-1A and RU-5B because of the failure of electrical submersible pumps but did replace those ESPs.

Walsh said CIE has also applied to contract the Redoubt unit and create a new south step out participating area, an application on which a decision is pending.

For the 18th POD CIE is going to look at results of current and planned enhanced recovery waterflood efforts and convert additional non-producing wells to waterflood if appropriate; change out a failed ESP in the RU-9 well and perhaps stimulate that well with hydraulic fracturing; and drill and stimulate a sidetrack of the RU-4A wells and use it for waterflood injection.

The division also approved the 27th POD for the West McArthur River unit, which is producing 805 bpd, excluding Sword and 1,177 bpd with Sword, with cumulative production of 14.4 million barrels, excluding Sword, and 15.1 million barrels including Sword, through November.

Gas production is at 181,000 cubic feet per day, including Sword, 124,000 cubic feet excluding Sword, with cumulative production of 3.87 bcf including Sword and 3.67 bcf excluding Sword.

For the previous 26th POD CIE continued analysis of production and enhancing production through perforation adds, well workovers and pump replacements.

"CIE additionally committed to developing and permitting drilling plans for the Sabre project," Walsh said.

During the 26th POD CIE also completed the process of moving production processing of WMRU wells to the Kustatan Production Facility, a newer facility capable of handling greater production volumes. CIE also discontinued use of high-pressure oil injection jet pumps, simplifying operations and increasing overall field safety.

For the 27th POD CIE will continue to explore methods to enhance production, manage production decline and increase total ultimate recovery from existing wells; and continue to analyze production from unit wells and enhance production as appropriate through perforation adds within wells, well workovers and pump replacements. CIE will also continue to permit drilling plans for the Sabre offshore exploratory well, which would be drilled from a jack-up.

Hilcorp PODs

Walsh approved PODs for the Hilcorp-operated Ivan River, Lewis River and Pretty Creek units, all producing gas, and the Pretty Creek gas storage lease.

The Ivan River unit was formed in 1967; production began in 1990. Cumulative production was 86.1 bcf through the end of 2017, with production declining from some 0.750 million cubic feet per day in 2016 to 0.651 million cubic feet in 2017.

Hilcorp continued production from the Sterling-Beluga and Tyonek participating areas during the 2017 POD and continued using the IRU 14-31 and 13-31 wells for disposal for the Lewis River, Pretty Creek, Ivan River and Stump Lake units.

Hilcorp plans to continue to produce from the Sterling-Beluga and Tyonek PAs during the 2018 POD, Walsh said, and "also plans to continue a comprehensive field study for further development."

Lewis River has been on production since 1984 and has produced 15.4 bcf of cumulative gas through the end of 2017. Hilcorp produced 128 million cubic feet of gas in 2016, and increased production to 137 million cubic feet in 2017.

Hilcorp continued production from Lewis River gas pool No. 2 in 2017, with one well on production. No drilling or wellwork was done, but a permanent sand separator was installed.

During 2018 Hilcorp plans to continue production from the same pool, and "also plans to continue a comprehensive field study for further development." As at Ivan River, no major facilities upgrades are planned, but Hilcorp will address needs as they arise.

Pretty Creek has been in production since 1986, producing cumulatively 9.51 bcf of gas through the end of 2017. Production from Pretty Creek has been intermittent and variable, with average daily rates of some 0.028 million cubic feet per day in 2017.

The Pretty Creek gas storage lease was issued in 2005 and renewed in 2015. For 2017, 32 million cubic feet of gas were injected and 172 million cubic feet withdrawn.

Hilcorp continued production from the Beluga PA during the 2017 POD, with one well in production, and no drilling, well or facility work performed.

During 2018 Hilcorp plans to continue to produce from the Beluga PA and plans to review existing wells for further development. ●

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CORRECTION

Tug on station

The article "New vessels arrive" in the April 8 issue of Petroleum News incorrectly stated that when a tanker outbound from the Valdez Marine Terminal departs Prince William Sound a sentinel tug remains on station at the Hinchinbrook Entrance to the Sound until the tanker is 70 miles out into the Gulf of Alaska. In fact, the tug remains on station until the tanker is 17 miles out into the Gulf.

Petroleum News apologizes for any confusion.

GOVERNMENT

Legislature confirms RCA commissioners

During a joint meeting of the House and Senate, on April 10 the Alaska Legislature confirmed the appointment of three commissioners for the Regulatory Commission of Alaska: Janis Wilson, Paul Lisankie and Antony Scott. The confirmations take effect on May 2.

Janis Wilson is already an RCA commissioner: Her appointment will continue uninterrupted. Paul Lisankie is also currently serving as a commissioner, having been appointed at the beginning of February as a replacement for Commissioner Norman Rokeberg, who had announced his early retirement. Lisankie will fill the remainder of Rokeberg's term, which expires March 1, 2019. Scott is replacing Commissioner Rebecca Pauli, who is leaving the commission.

Scott was chief economist for the RCA between 2000 and 2002, before becoming a commercial analyst in Alaska's Division of Oil and Gas, where he gained expertise in the management and economics of the trans-Alaska pipeline. In 2012 he became senior commercial analyst in the Center for Research Services in the University of Alaska Fairbanks. Work conducted during his time at UAF included a study into the economics of energy supplies in Fairbanks, and a study for the RCA into the various issues relating to the management of the Alaska Railbelt electrical system. Since July 2015 Scott has been working as commercial manager for the Alaska Liquefied Natural Gas project.

—ALAN BAILEY

● GOVERNMENT

Committee moves HB 322, increases fines

House Finance amends spill bill originating in House Resources; fines DEC can charge for spills increased to account for inflation

By KRISTEN NELSON
Petroleum News

House Finance has moved House Bill 322, the House Resources bill increasing oil spill fines to keep up with inflation. The 6-4 committee vote, April 7, was largely on party lines. The bill is now in House Rules and goes next to the House floor and, upon House passage, to the Senate.

There is no companion bill in the Senate, so the measure will start from scratch in that body.

The goal of the bill, crafted by House Resources, is fundamentally an update in spill fees and penalties which can be charged by the Department of Environmental Conservation, House Resources co-Chair Andy Josephson, D-Anchorage, told House Finance in March 29 and April 7 hearings.

He said the bill also adds administrative penalties since it is very expensive and time consuming for the department to deal with small penalties through the legal system. It is easier, Josephson said, if administrative penalties are available — and in other areas, such as food safety and public drinking water — the department can issue administrative penalties. He said the federal Environmental Protection Agency requires that administrative penalties be available in areas where the state has taken primacy.

Kristin Ryan, director of DEC's Division of Spill Prevention and Response, said numbers in the bill were basically adjusting penalties to account for inflation since the penalties were imposed.

That was true of some changes, but in other cases the amount was simply doubled, where accounting for inflation would have made the increase about four times.

House Finance amendments

Amendments in House Finance by Rep. Dan Ortiz, a non-affiliated member from Ketchikan, raised amounts for civil penalties for non-crude oil spills of more than 18,000 gallons into aquatic environments and onto public land from an existing $10 per gallon to $40 per gallon in an anadromous environment. The House Resources bill had proposed $20.

For spills into an estuary, $2.50 is in place, the bill proposed $5 and the Ortiz amendment $10.

The current fine is $1 (in open ocean), the House Resources version proposed $2; the amendment increased that to $4.

> *The goal of the bill, crafted by House Resources, is fundamentally an update in spill fees and penalties which can be charged by the Department of Environmental Conservation, House Resources co-Chair Andy Josephson, D-Anchorage, told House Finance in March 29 and April 7 hearings.*

The Ortiz amendment increases the fines in line with inflation since those penalties were established in 1977.

Penalty increases proposed in the bill for crude oil spills of more than 18,000 gallons remained as proposed, from $8 per gallon for spills less than or equal to 420,000 gallons to $16 per gallon; and for spills greater than 420,000 gallons from $12.50 to $25 per gallon. Those penalties were set in 1989 and have not been raised; the increases are in line with inflation.

In a separate amendment, also by Ortiz, the minimum civil penalty for illegal discharges of oil and crude oil of less than 18,000 gallons was raised from no less than $500 and no more than $100,000, to no less than $2,000 and no more than $400,000; the House Resources version of the bill had set those amounts at $1,000 and $200,000. The penalties were established in 1976 and had not been raised; the 2018 equivalent amounts are more than $2,000 and $400,000.

Unchanged from the House Resources version was an increase in the penalty for each day after the violation from $5,000 to $25,000, greater than the adjustment for inflation.

The bill also increases the amounts for civil penalties for discharges from cruise ships, which have not been raised since enacted by voter initiative in 2006.

A requirement in the House Resources bill that penalties be adjusted annually based on the consumer price index was changed in an amendment offered by House Finance co-Chair Paul Seaton, R-Homer, to every three years. Seaton also offered an amendment which inserted a definition of produced water into the bill, and another amendment which required that oil spill response plans be submitted to the department electronically.

All the amendments offered in House Finance were adopted. ●

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POWER DEBATE

energy also say that the balkanized system management acts as an obstacle to the viable implementation of renewable energy generation.

The authority proposed in HB 382 would steer the system in the direction of implementing economic dispatch across the Railbelt, an arrangement in which maximum use would continuously be made of the most efficient power generation facilities. The authority would also establish a universal transmission tariff and nondiscriminatory access to the transmission system.

Three concepts

Currently there are three different concepts being floated for a system operator: the concept encapsulated in HB 382; a somewhat similar concept being put forward by the Alaska Energy Authority; and a proposal for a Railbelt Reliability Council being prepared by consultancy GDS Associates Inc. for the Alaska Railbelt Cooperative Transmission and Electric Co., or ARCTEC, an organization with membership of four of the six Railbelt utilities.

Each concept envisages a system operator organization, regulated by the Regulatory Commission of Alaska and overseen by a board of governors. The composition of the board is important in achieving a balance between the expertise of the utilities and the desire for fair representation for all stakeholders in the system.

The GDS proposal, due to be published in late April, is an outcome of voluntary efforts by the utilities to tackle the Railbelt power system issues. Proponents of HB 382 have expressed frustration at the length of time that these voluntary efforts are taking to achieve the necessary goals and have expressed skepticism over whether the goals can be achieved by voluntary means.

All three concepts for the unified system operator involve broadly similar approaches. However, the GDS proposal does not include economic dispatch: GDS has suggested that the potential for economic dispatch across the Railbelt does warrant further study.

The RCA perspective

During the April 5 meeting, RCA Commissioner Robert Pickett reviewed the long, multiyear history of failed attempts, either through voluntary efforts or through legislation, to unify the electrical system. One problem arising from the fragmentation of the system ownership and management has been the construction of more new generation capacity than is needed in an era of declining electrical loads, with around $1.5 billion spent on new facilities, Pickett said. In 2015 the RCA wrote to the Legislature, stating that the transmission and generation system needs a more unified approach. Since then the commission has been encouraging the utilities' voluntary efforts to meet the commission's requirements.

As part of those efforts the utilities have been working with the American Transmission Co., a transmission company that operates in the Lower 48, to develop a proposal for a single company to operate the Railbelt transmission grid, Picket said. Last fall the utilities indicated that they anticipated filing their proposal with the commission but so far that filing has not appeared. In a public meeting in May the commission is going to ask for an update, Pickett said, also commenting that many of the issues revolving around the transmission company relate to the differing economic impacts on different utilities.

Pickett said that economic dispatch is also important. In Southcentral Alaska there has been a delay in filing a commercial agreement with the commission for an economic dispatch arrangement between Chugach Electric Association, Municipal Light & Power, and Matanuska Electric Association — the commission will also be asking for an update on that in May, he said. He said that, although he understands that some people would like to see faster progress, the issues involved are very complicated and the utilities are also trying to juggle other important tariff-related questions. The commission will keep the pressure on, he said.

However, he said that his biggest concern is the lack of a single set of enforced reliability standards for the Railbelt. The utilities have been working to reconcile the two existing sets of standards for the grid and anticipate publishing a unified set in mid-April. But the existing standards have "gaping holes," Picket said. Pickett said that it is his intention to introduce a rule-making docket in the commission in April, to enforce mandatory standards.

Pickett also commented that states that have made most progress in implementing renewable energy have renewable energy portfolio standards, something that Alaska does not have.

MEA supports voluntary efforts

Julie Estey, director of external affairs for Matanuska Electric Association, said that MEA opposes HB 382 and would prefer to continue with the utilities' voluntary efforts that, she said, are making progress.

Estey said that the Railbelt electrical system differs from systems in the Lower 48. It covers a large area but has a relatively low load and is very isolated — it is necessary to balance the cost of the infrastructure against the relatively few people that it serves. However, the reliability of the system is very high.

The transmission intertie between Southcentral and the Interior represents a single point of failure for the interchange of power between the two regions. That has necessitated additional generation and a battery system in Fairbanks. Fuel for power generation is also expensive relative to fuel in the Lower 48, Estey said. She also commented that the Railbelt system can only handle relatively small variations in the frequency of the alternating current power supply, a factor that impacts the practicalities of handling fluctuating loads or generation, and that also results in a need for higher levels than normal of reserve power on the system.

A new era

Although the utilities could have cooperated better with each other in the past, there is now a new era, with new people involved in leadership positions, making decisions under new circumstances: The utilities are now moving forward in working together, Estey said. And 70 percent of MEA's customers want to see more use of renewable energy, she said. The utilities have been taking steps to meet the requirement of the RCA's 2015 directive and they are succeeding, she said. The utilities are going to put some proposals before the RCA. In the next legislative session it will be possible to figure out whether any changes to statutes will then be required, Estey said.

With the issues involved being complex and several initiatives proceeding concurrently, and with the necessity to ensure that solutions do not have unintended consequences, progress is perhaps slower than some would like, Estey said. All the utilities have worked with the American Transmission Co. to develop an economic model of the Railbelt electrical system, to gain a better understanding of the economic impacts of changes to the system. That modeling indicated the possibility of gaining $15 million to $25 million annually across the Railbelt from economic dispatch, with about 80 percent of those savings coming just from the pooling of power and transmission for MEA, ML&P and Chugach Electric, the Southcentral utilities. Most of the remaining benefit would come from Golden Valley Electric Association joining the economic dispatch arrangements.

Moving forward

In terms of the timeline to meet the RCA's requirements, 2015 saw a power trading agreement between the utilities, 2016 saw the development of the model of the electrical system, and 2017 saw a memorandum of understanding between the Southcentral utilities to implement economic dispatch through a tight power pool, with testing of the tight pool arrangements taking place since then. The utilities are obtaining computer systems to replace the spreadsheet-based arrangements used for the testing of the pool. The other utilities are evaluating the benefits of joining the tight pool arrangements. Upcoming activities for this year include the filing of the Railbelt Reliability Council structure with the RCA, an RCA filing for the Southcentral tight power pool, the transmission company decision, and improved communications about what is happening, Estey said.

GDS has received indications that all the utilities will ultimately support the Railbelt Reliability Council, the system operator organization that would oversee the complete electrical system, Estey said. MEA supports the board structure that GDS is proposing for the RRC, with the utilities having three of the nine seats on the board, she said.

MEA wants to see an organization, regulated by the RCA, that is transparent, is independent from conflicts of interest, is inclusive of many voices, ensures that everyone understands the consequences of decisions, and is rooted in technical excellence, Estey said.

She also commented on the new generation facilities that the utilities have built in recent years, saying that new facilities are efficient and replace old, inefficient plant. The overall objective of the utilities is to minimize the amount of fuel that they use, she said. And all the utilities want a clear path for renewables on their system. The RRC and its board, if implemented, would be in control of the system, making the necessary decisions, Estey said.

An independent power produce perspective

Mike Craft, owner and operator of a wind farm at Delta Junction, spoke to the committee about the challenges for an independent power producer in gaining access to the Railbelt electrical system under the current system management arrangements. Craft wants to expand his wind farm but has not succeeded in forming a commercial agreement with Golden Valley Electric Association, the local utility. GVEA has said that the expansion is not commercially viable.

Craft said that the Railbelt utilities provide a good service. However, the utilities appear to have a self-build bias in the development of new facilities — three major renewable energy projects have become "dead on arrival" at the RCA, mostly because of integration and transmission issues, he said. He commented that he had sited his wind farm at a particularly favorable location and that the use of wind energy can provide a means of tackling air quality problems that plague the Fairbanks region.

It is particularly important to have an unbiased system operator to oversee the electrical system, along the lines of what is proposed in HB 382 — a local utility cannot by itself address the big issues that the electrical system faces, Craft said. ●

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BONDING BILLS

Deputy Commissioner of Revenue Mike Barnhill said it was impossible to know what the expectations of a small explorer would have been, but he noted the state marketed the credits based on state participation in the life cycle of projects.

His presentation materials included an ad the state used to promote the credits, which says: "We do not just talk big, we follow through big — with cash!"

As to the expectation that the small companies had that payment would be immediate, Tax Division Director Ken Alper said that for many years there was full payment and the expectation of full payment.

Constitutional issue

Sen. Bill Wielechowski, D-Anchorage, questioned the constitutionality of the bonds in the Senate Resources hearing, saying state debt is not permitted under the Alaska Constitution without approval of the voters.

A letter on the subject from the state debt manager in the Department of Revenue and an assistant attorney general in the Department of Law, said that was not the case.

The legislation, they said, authorizes issuance "subject to appropriation bonds which is a form of financing that has been utilized in the past by the state and has not been considered to be unconstitutional state debt."

House Resources co-Chair Geran Tarr, D-Anchorage, said her concern is that there is already a mechanism on the books to pay off the credits, and said she would prefer finding a way to pay out faster than the statutory schedule, rather than bonding.

The debt is now interest free, she said, but once the state bonds for it, payment on that debt would have to the prioritized over other needs in the state. She said she would prefer to have the state get its fiscal house in order before taking on more debt.

AOGA concerns

The Alaska Oil and Gas Association told the committees that it supports expedited payment of earned credits. It said in written testimony to House Resources that the governor's plan is an innovative approach to repay a portion of the earned credits at a reduced rate by lowering the refunding rate to cover the state's bond finance costs.

AOGA said it "has concerns about the steep discount and other provisions of the bill," but is committed to working to find an equitable solution.

And it isn't just oil and gas companies — refinery tax credits are also involved. Petro Star told House Resources in written testimony that it and Arctic Slope Regional Corp. made significant investments in asphalt for the Interior and lower-cost fuel for Golden Valley Electric Society, and to date, "have only received a small fraction of the refinery tax credits claimed."

—KRISTEN NELSON

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GAS SUPPLY

Natural Gas — the idea is that IGU will combine with FNG to form a single, consolidated gas utility in Fairbanks.

As a necessary precondition for the sale of Pentex, the IEP formed a three-year gas supply agreement with Hilcorp Alaska. Hilcorp delivers gas to a small Pentex-owned liquefied natural gas plant at Point MacKenzie on Cook Inlet. A Pentex subsidiary transports the LNG by road to Fairbanks. Following the IGU acquisition of Pentex, the plan is to expand the gas supply, through the construction of a new LNG storage facility in Fairbanks, and potentially through the expansion of the existing LNG plant.

During discussions leading to the Pentex purchase agreement, comment was made that the relatively short term of the Hilcorp gas supply agreement would allow flexibility, should some alternative means of boosting the Fairbanks gas supply emerge. Possibilities include a proposed new LNG plant near Houston, on the Alaska Railroad, and the possibility of Doyon Ltd. discovering natural gas from exploration drilling that the Native corporation is conducting in the Nenana basin.

Flexibility remains

In an April 9 email Stewart told Petroleum News that IGU's potential new gas supply contract would not jeopardize the possibility of other players becoming involved in the supply of gas for Fairbanks. The purchase agreement for Pentex allows flexibility in the means of expanding the Fairbanks gas supply and, given the potential scale of gas demand in Fairbanks, the opportunity for market entry by players other than Hilcorp and the new potential supplier will remain for the foreseeable future, Stewart wrote.

—ALAN BAILEY

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ICEWINE 3-D

Accumulate Energy Alaska, which operates in Alaska for 88 Energy, has already secured multiyear permits for two well locations, Bravo and Charlie, in the 3-D acquisition area. The Alaska Division of Oil and Gas describes the objective of the wells, 22-25 miles west of the Franklin Bluffs pad, as a conventional Seabee formation play.

Yukon Gold

88 Energy said a second 3-D seismic survey was conducted in late March in an area of leases the company recently acquired which includes an existing well, Yukon Gold 1.

These tracts, south of Point Thomson and west of the Arctic National Wildlife Refuge, were acquired in the state's 2017 North Slope areawide lease sale by 88 Energy subsidiary Regenerate Alaska Inc., which was the successful bidder on a block of some 32,800 gross acres, including the existing well, which was drilled by BP in 1993-94. That well was an oil discovery and the state has estimated recoverable reserves of some 120 million barrels.

The state approved an SAExploration application for the Yukon 3-D in February. The permit said the project included some 251 square miles of 3-D acquisition.

88 Energy said the Yukon Gold 3-D survey was fast tracked to take advantage of a seismic crew which was available in the latter part of the 2018 seismic season. Final processed products from the Yukon Gold shoot are expected in the fourth quarter.

Icewine testing

The company said it is finalizing planning for re-opening the Icewine No. 2 well for flow testing in the April-May timeframe, with exact timing dependent on warmer temperature. Drilling at Icewine No. 2 began in the second quarter of 2017, with production testing ongoing.

—KRISTEN NELSON

Petroleum news Oil Patch Bits

Alaskan heroes to be honored at Red Cross breakfast

The American Red Cross of Alaska said it will honor individuals for acts of heroism throughout Alaska at the 19th annual Real Heroes Breakfast, presented by ConocoPhillips.

This inspiring event raises critical funds for the Red Cross of Alaska. The event takes place in the Hotel Captain Cook ballroom in Anchorage on Tuesday, April 17. Doors open at 6:45 a.m. and the program begins promptly at 7 a.m. A media box will be available.

These everyday heroes are nominated each year by fellow Alaskans for exceptional acts of bravery, quick-thinking, selflessness, and skill. "Every day ordinary people roll up their sleeves and perform extraordinary act of heroism," said Tanguy Libbrecht, Red Cross of Alaska CEO. "Red Cross's lifesaving programs and services equip Alaskans with skills and information necessary to prevent, prepare for, and respond to emergencies. It is an honor to recognize these extraordinary Alaskans for their contributions to our communities."

The event will be emceed by Red Cross of Alaska Board Chair Josh Howes and board member Dan Newman, along with presenters from 10 corporate partners, who have sponsored the heroes.

Approximately 500 guests are expected to pay tribute to more than 20 heroes in 10 categories who, in the last year faced challenging situations and made the selfless decision to help someone in need, or where a part of a program that has improved the overall safety of our state. The ceremony will spotlight each hero's story and award them with a Red Cross hero medal.

Arctic Slope Regional Corp. mourns Sen. Daniel Akaka

Arctic Slope Regional Corp. said April 6 that following today's passing of former Hawaii Sen. Daniel Akaka, it was issuing the following statement:

"ASRC mourns the loss of Senator Daniel Akaka. Often regarded as Alaska's fourth senator, Senator Akaka had a deep connection to our state. He served our country in World War II and supported our veterans and military service men and women throughout his tenure in the United States Senate. A true hero, Senator Akaka always stood with Alaska on key Alaskan issues before Congress. We stand with our brothers and sisters of Hawai'i in the mourning of a true American."

Companies involved in Alaska and northern Canada's oil and gas industry

All of the companies listed above advertise on a regular basis with Petroleum News

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HB 411

tax applying only to the PTV amounts above each value.

Revenue's view

This is not an administration bill but the Department of Revenue provided an analysis.

Ken Alper, director of Revenue's Tax Division, agreed that HB 411 was very similar to the House version of HB 111 last year, with slight differences in supplemental tax brackets and the elimination of the $5 per barrel credit for GVR (gross value reduction) oil.

Another similarity, Alper said, is that the revenue impact is concentrated at oil prices of $50-$90.

The tax brackets are different from ACES progressivity in that ACES applied the highest tax calculation to all oil profits while HB 411 only changes the higher rate on the portion above the rate cutoff.

Revenue Commissioner Sheldon Fisher told the committee that with what appears to be legislative consensus on a partial fiscal plan using Permanent Fund earnings, there remains a budget gap in the $500 million to $700 million range.

He said the administration believes the most appropriate mechanism to fill the gap is a broad-based tax tied to the state's overall economy.

Fisher said the Legislature set in motion a process last year to revisit fair share issues and said it may be premature to address substantial tax revisions under that process is complete.

The consultant

Rich Ruggiero of In3nergy, a consultant to the Legislature, said in an April 11 hearing on the bill that lawmakers should focus on what is necessary to bring on new North Slope developments. He recommended lowering the base tax, 10 percent is the number cited in his slide presentation, and making the highs higher. He told legislators that because costs rise with sustained price increases, windfall taxes will only occur with short duration price spikes. With sustained price increases, costs rise, lowering the production tax value, which includes costs the companies incur in producing the oil.

Ruggiero said that with a liquefied natural gas project in the works, the Legislature should put together a comprehensive new fiscal system before next January.

Industry opposition

The committee also heard from the oil industry, which was uniformly opposed to HB 411.

Kara Moriarty, president and CEO of the Alaska Oil and Gas Association, noted the unstable nature of the state's tax policy, and said changes since 2005 have been opposed by industry, with the exception of the 2010 Cook Inlet Recovery Act, which provided incentives for industry. All other changes have involved tax increases, and were either entirely opposed, supported with concerns or opposed in the final version.

She said Alaska is only capturing 1.7 percent of total U.S. industry investment, less than $2 billion in capital annually in each of the last two years and said there is a need for at least $3.6 billion in investment capital to grow production.

She also said that at $60 oil, with costs and state taxes are removed, producers earn $31 per barrel in West Texas, $12 on the North Slope and potentially $1.50 per barrel for a new Alaska field. Where would you invest, she asked.

Scott Jepsen and Paul Rusch, testifying for ConocoPhillips, told legislators there is a robust outlook for North Slope investment, but said the state faces competition from unconventional fields in the Lower 48 where there is enormous potential, tens of thousands of drilling opportunities, with a lower cost of supply. Those opportunities are closer to market, easier to permit and are in areas with stable fiscal policies.

Taxes and royalties are only part of the equation, they said — total cost drives competitiveness.

And since HB 411 raises taxes at lower prices it will likely cause reduced investment at times when the state's economy and the North Slope need more investment.

Alaska remains competitive, they said, because of a focus on cost reduction and efficiencies, with the core structure of Senate Bill 21 remaining unchanged for more than four years.

Damian Bilbao and Lewis Westwick, testifying for BP, said the impact on BP Alaska of HB 411 would be some $200 million, the equivalent of two rigs at Prudhoe ($70 million) and one new North Slope pad ($120 million) and said the impact could mean no drilling at Prudhoe and no spend on a new pad.

Addressing BP's Alaska profits, they said while $830 million was reported, that included $454 million in one-time items, primarily driven by the change in the federal corporate income tax and excluded $258 in pipeline and shipping costs.

The company's actual profit in Alaska in 2017 was $118 million, they said, noting that BP Alaska made total payments to the state in 2017 of some $543 million.

In language which mirrored his testimony last March on the House version of HB 111, Dan Seckers, ExxonMobil tax counsel, said he was disappointed to be in June testifying on another proposed tax change. He said ExxonMobil supported the AOGA testimony and echoed the testimony of other industry representatives on the negative impact the bill would have on investment in Alaska. Seckers also noted that the bill takes effect July 1, which would mean that companies would have to change course in midyear on how they figure their taxes.

In addition to others testifying live, the committee got written testimony from Benji Johnson, president and CEO of BlueCrest Energy, which operates the Cosmopolitan project in Cook Inlet. While Cook Inlet is not affected by the bill, he said that for the "long term good" of the state BlueCrest urges legislators not to support the bill.

He cited competition for investment dollars and said while super giant finds can justify enormous investments, "smaller finds are generally much more sensitive to costs" and will only be developed if returns can compete with opportunities elsewhere.

Johnson said production taxes in Alaska are "one significant component" of the higher costs in Alaska, compared with Lower 48 basins. Approval of HB 411 would, he said, provide another confirmation of the state's disinterest in promoting competitiveness and while there would probably be short-term revenue increases, "we believe it would be at the cost of much larger lost potential growth for many years into Alaska's future."

As Petroleum News went to press the committee had two more hearings scheduled on HB 411. ●

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DRILLING RECORDS

minimizing our environmental footprint," said Shon Robinson, manager of drilling and wells for ConocoPhillips Alaska. "CD5-25 will produce from over 4 miles of reservoir in the long lateral and from over 6 miles of reservoir when both laterals are included. Innovation and teamwork were a huge part of safely drilling this well," he said.

CD5 is the first commercial oil development on Alaska Native lands within the National Petroleum Reserve-Alaska, the company said. Production began from CD5 in late 2015. The original production target was 16,000 barrels per day; the field as averaged 37,000 bpd. The company said the significant increase in production at CD5 is due in part to wells like CD5-25.

ConocoPhillips said Doyon 19 moved to the Greater Moose's Tooth 1 drill site in NPR-A in mid-March to begin drilling that project's first well. GMT1 is expected to come online in late 2018 and peak at some 30,000 bpd.

In 2016 ConocoPhillips Alaska set a record for the longest well ever drilled in Alaska at CD5 with an injection well, also drilled by Doyon 19, with a measured depth of 26,196 feet and a vertical depth of some 7,400 feet; the well included a horizontal section of 17,228 feet.

CD5 was planned for 15 wells, but the company said in 2016 that based on results from the first 10 wells, 18 more would be added, bringing the total to 33 wells.

ConocoPhillips Alaska spokeswoman Natalie Lowman told Petroleum News in an April 10 email that there have been two separate extension projects at CD5, the first from 15 to 33 wells, completed in the past winter season, and a second extension from 33 to 43 wells which will occur in 2019. She said the increase in well count represents an incremental gross investment of $430 million in addition to the initial invest of $1.1 billion gross.

"The increase in increase in well count does not require any increase in gravel footprint," Lowman said.

—KRISTEN NELSON

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TRANS MOUNTAIN

crude bitumen to 890,000 barrels per day through Vancouver to Asia, insisting that the pipeline is not in Canada's national interest.

"It's been said we are somehow compromising the national climate action plan and I profoundly disagree with that," he said. "I reject the notion that our opposition to risking our coast and our economy is somehow tied to the climate plan."

Horgan also dismissed any suggestion that his government's position is creating a constitutional crisis over the Canadian government's right to approve the transport of energy resources across provincial borders.

Federal approval in 2016

Notley told her cabinet April 9 it's time for the government of Prime Minister Justin Trudeau to show that its 2016 approval of Trans Mountain is worth more than the paper it`s written on.

In a "frank" phone conversation April 9, she told Horgan Alberta "will now be moving forward very aggressively."

The Globe and Mail said in an editorial April 8 the federal government "must use whatever tools it has, courts included, to re-establish its jurisdiction and get Trans Mountain back on track."

"To do otherwise threatens the basic tenets of confederation. A province cannot use underhanded tactics to effectively seize control of the development of (Canada's) natural resources."

The national newspaper accused Horgan's government of "naked hypocrisy" since gaining power last summer by "using its stated desire to protect the environment as a reason for delaying Trans Mountain. At the same time, however, it is supporting the development of its natural gas reserves, offering tax breaks to (the C$40 billion LNG Canada project) that includes ... a new pipeline and a new tanker terminal on the B.C. coast."

Jobs, revenue cited

Notley said Horgan is wrong if he thinks B.C. can "mess" with Trans Mountain, which she noted will create thousands of jobs and billions of dollars in revenue that will benefit all of Canada.

> *"A company cannot resolve differences between governments. While we have succeeded in legal challenges (estimated at 14) to date, a company cannot litigate its way to an in-service pipeline amidst jurisdictional differences between governments."*
> *—Kinder Morgan CEO Steve Kean*

"Let me be absolutely clear ... they cannot mess with Alberta," adding that if her government is forced to invest public money in the project "we will be a significantly more determined investor than British Columbia has dealt with up to this point."

Notley called on the Trudeau government to "work in defense of Alberta and working people in Western Canada in the way they have in the past for other parts of this country," pointing to federal assistance for Ontario's auto sector and Quebec's aerospace industry in times of crisis.

In a rare move, Jason Kenney, leader of Alberta's United Conservative Party, agreed with Notley, although he said Kinder Morgan's announcement was predictable.

He accused the federal government of standing by "passively uttering meaningless bromides for the past nine months.

"Now is the time for federal action. It is time for the federal government to act like a federal government, for our prime minister to lead like a prime minister should ... in the national interest," Kenney said.

While "philosophically opposed to corporate welfare," he said that where there has been a "major market failure there is a compelling case for the state to come forward, using its credit, its financial leverage, to ensure economic progress. I believe this is such an instance."

Trudeau: 'rule of law'

Before Kinder Morgan delivered its ultimatum, Trudeau met with eight oil patch chief executive officers in Fort McMurray on April 6 and again insisted that the pipeline expansion will proceed.

"Canada is a country of the rule of law and the federal government will act in the national interest. Access to world markets for Canadian resources is a core national interest. The Trans Mountain expansion will be built," he declared.

Natural Resources Minister Jim Carr told reporters April 8 that Horgan should end all threats to delay Trans Mountain.

His government's actions "stand to harm the entire Canadian economy," while promising to use "all possible options" to force B.C. to back off.

But he would not comment when asked if that could include deploying the Canadian military to end protests and disruptions at Trans Mountain sites.

When pressed, Carr would only say: "We are not ruling anything out ... all options are on the table."

C$1.1 billion spent

Kean said in a news release April 8 that his company, having already spent C$1.1 billion on the project, is taking steps to protect its value rather than risking additional billions of dollars on an outcome that its beyond its control.

"A company cannot resolve differences between governments. While we have succeeded in legal challenges (estimated at 14) to date, a company cannot litigate its way to an in-service pipeline amidst jurisdictional differences between governments."

He said the "uncertainty created by B.C. has not been resolved, but instead has escalated into an inter-governmental dispute."

University of Alberta economist Andrew Leach said it was not reasonable to compare Energy East, TransCanada's planned link from the oil sands to Atlantic Canada, which he rated as the "least attractive option to get crude to market," while Trans Mountain "is the best option and not building it significantly compromises the value of (Alberta) natural resources."

Andrew Wilkinson, leader of the British Columbia Liberal Party, said Horgan has "let his activist environment minister (George Heyman) ignore the rule of law as this government picks winners and losers by willfully ignoring the constitution."

"Investors large and small interested in our province need to know the provincial government will treat everyone fairly and equally. This is a project that has received federal approval and falls under federal jurisdiction, yet (the New Democratic Party government) used it to pick a trade war with Alberta and start a confrontation with the federal government," he said. ●

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