Petroleum news

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page 3 Q&A: Wielechowski: State should lead; expects concession demands

May Mining News inside

The May issue of North of 60 Mining News is enclosed.

Linc may take partner at Umiat

Linc Energy Ltd. may form a joint venture to pursue development of the Umiat field.

Having recently completed a successful flow test at the undeveloped oil field in the foothills of the Brooks Range Mountains, the Australian company said it is "evaluating the advantages of introducing an industry partner to assist us in the future development."

Earlier this year, the subsidiary Linc Energy (Alaska) Inc. completed Umiat No. 23H, the first horizontal well drilled at the oil field discovered by U.S. Navy contractors in 1946.

A subsequent flow test produced a sustained rate of 250 barrels of oil per day, or 650 barrels total during four flow tests conducted over a seven-day period at the field, according to the company. The well flowed at a peak rate of 800 bpd, Linc

see **LINC JV** *page 14*

Buccaneer official Curtis Burton resigns after board suspension

A top official of Buccaneer Energy Ltd. has left the company.

Chief Executive Officer and Managing Director Curtis Burton resigned from the board of the Australian independent effective May 12, according to a statement from Buccaneer.

In March, Buccaneer suspended Burton with pay "allowing for a review to be conducted." With the review completed, the board held a "special purpose meeting" on May 12 to review the findings and "determined that cause exists for terminating Mr. Burton's employment agreement." The company provided no further details.

In an open letter to shareholders on May 7, Burton said that he and his management team had submitted a plan to the board

see **OFFICIAL RESIGNS** *page 14*

EXPLORATION & PRODUCTION

Massive Beaufort plan

JV reviewing program that could involve deepest well yet in Canadian Beaufort

By GARY PARK
For Petroleum News

Imperial Oil, backed by its controlling shareholder ExxonMobil with BP Canada as a partner, is assembling one of the most comprehensive oil and natural gas exploration programs in Canadian history as it advances plans to drill in the Beaufort Sea.

A 455-page project description has been submitted to an Inuvialuit Environmental Impact Screening Committee for a joint venture drilling program that could involve the deepest offshore well yet drilled in the Arctic.

The proposal involves drilling one or more exploration wells about 75 miles northwest of the village of Tuktoyaktuk on the shores of the Beaufort.

> *The proposal now faces a multi-layered screening process that is targeted at starting the two-year drilling program in 2020.*

The plan is to drill on Exploration Licenses 476 (Ajurak) and 477 (Pokak) where water depths range from about 200 feet to 5,000 feet, with an independent consultant calculating the well depth could reach 34,000 feet.

Imperial and ExxonMobil secured their EL in 2008 for a pledge to spend C$585 million, while

see **BEAUFORT PLAN** *page 13*

EXPLORATION & PRODUCTION

Promising indications

Exploration of Alaska Interior basins points to much potential for oil and gas

By ALAN BAILEY
Petroleum News

While two deep exploration wells drilled in Alaska's Nenana basin in recent years failed to find commercial quantities of oil or gas, the wells did provide tantalizing evidence for a petroleum system.

Findings included hydrocarbon source rocks, excellent reservoir sands and shales with the potential to trap hydrocarbon pools, exploration consultant Michael Richter told the 2014 Alaska Geological Society Technical Conference on May 16. Testing of rock samples from the wells, coupled with surface geochemistry, has demonstrated the existence in the subsurface of natural gas and natural gas liquids, while the analysis of potential source rocks, coupled with estimations of the subsurface temperatures, has pointed to the possibility of oil in the basin, Richter said.

> *Findings included hydrocarbon source rocks, excellent reservoir sands and shales with the potential to trap hydrocarbon pools, exploration consultant Michael Richter told the 2014 Alaska Geological Society Technical Conference on May 16.*

see **INTERIOR BASINS** *page 14*

FINANCE & ECONOMY

Strong jobs outlook

Thousands of workers needed to sustain Alaska oil industry, workforce plan says

By WESLEY LOY
For Petroleum News

Alaska will need thousands of new, highly skilled oil and gas workers to meet industry demand through the decade, the state Department of Labor and Workforce Development says.

The bulk will be needed to replace retirees or people who otherwise leave the industry, the department says.

The strong employment outlook reflects expected industry activity including new exploration and production projects. It doesn't count megaprojects such as a trans-Alaska natural gas pipeline, which could spark a huge hiring boom should it ever get off the drawing board.

The department makes its projections in the new "Alaska Oil and Gas Workforce Development Plan 2014-2018," available at http://tinyurl.com/o6dlgms.

> *A Department of Labor analysis showed that "an estimated 2,000 new workers will be needed by the Alaska oil and gas industry between 2010 and 2020 as a result of growth. An estimated 5,500 will be needed to replace workers who retire or otherwise leave the industry."*

An industry steering committee contributed to the plan. The committee included representatives from Buccaneer Energy, TransCanada, Shell, BP,

see **JOBS OUTLOOK** *page 16*

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● GOVERNMENT

Wielechowski: State should lead in gas

Anchorage Democrats fears results from SB 138 will be similar to Stranded Gas Development Act; expects demands for concessions

By STEVE QUINN
For Petroleum News

Sen. Bill Wielechowski has been among the most outspoken voices to changes in resource development. The Anchorage Democrat opposed Gov. Sean Parnell's gas line legislation that enabled the administration to enter into project management contracts.

He remains ardently opposed to the recent oil tax change that faces a repeal vote in August.

For nearly six years, Wielechowski's voice was among the majority. Today, with a different legislative lineup, he sits among the minority.

After the recent prolonged session ended, Wielechowski sat down with Petroleum News to discuss his views on a prospective gas line project, oil taxes, the Alaska Gasline Development Corp. board and the state's property assessment issues.

Petroleum News: You were among a handful of holdouts on SB 138. What didn't you like about it?

Wielechowski: I didn't think it was the right approach for the state. I had concerns for the lack of alignment. I know that was one of the things stressed early on was this finally puts us all in alignment, but it really doesn't. After we had our floor debate in the Senate where we really exposed the lack of alignment, they stopped talking about that. There is no alignment on the upstream end, there is no alignment on the downstream end, and I think that creates problems. The way it's structured is problematic. I would like to have to have seen it go out to an open bid to see if we could have gotten a better deal.

I think the biggest issue I had was this creates an 18-month period and we will go out to study building a gas line and the producers will come back and ask for concessions. The problem is we won't have very much leverage at this point. I think we gave away our leverage when we passed SB 21 last year. If you were really serious about building a gas line you would have extracted gas line commitments back then. If you were going to pass an oil tax bill, at least get something for it.

That was the significant piece of leverage we had at that time, which we didn't use.

We didn't get anything for passing that bill. I'm really concerned. It's like saying to someone what we are telling Joe Balash to do is you've got to come back in 18 months with a deal and these are the only people you can deal with.

A better way to do it is go out and strike a deal with buyers, like Tokyo Gas, or companies in Korea and China, then come back with a deal. This is like saying go buy a house. You can only buy this one particular house; you have to buy it from this one particular person. Come back in 18 months with a deal. The other person is not going to give you a good deal. They are going to want concession after concession after concession, especially if they don't have to sell you the house.

I think this is analogous to that and I hope I'm wrong, but I don't think this gets us to where we want to be.

Petroleum News: You noted how you would rather have had the pipeline portion put out for bid. That was tried under AGIA and there were no competing bids to review. There was only one conforming bid.


SEN. BILL WIELECHOWSKI

Wielechowski: I think the reason AGIA didn't work was because gas prices plummeted. I remember sitting in hearings where world-class experts were telling us gas prices were going to be $6, $10 and $12 into the foreseeable future, which was extremely profitable. Unfortunately, the experts all got it wrong. Had they got it right and had we been trading gas at the $10 range the next 20 or 30 years, we would be well forward with a gas line project. Shale gas has fundamentally changed gas line projects.

If I were running the show I would send out my DNR commissioner, put a team together and find some buyers, then go back to the producers and say we've got this deal. I think that's the way you get a gas line built. Turning over our deal making and sovereignty over to these companies and sort of putting our faith into their hands has not historically worked for us. I don't see that as any different.

Petroleum News: Between this and SB 21, you've not been happy on the oil and gas front.

Wielechowski: It's just a philosophical difference I have with this administration. It seems like they side with big business over the people of Alaska every chance they get. I don't think they met a tax break for an oil company they didn't like, but when it comes to fully funding education, they become fiscal watchdogs. On the oil tax, I felt like we were giving away state resources and getting nothing in return. On the gas line bill, I believe what will ultimately happen is there will be concessions not in the best interest in the people of Alaska. We will be giving away assets and getting little in return. The same holds true for the Alaska refineries bill. I was more than happy to help the small Alaska refineries. It didn't make any sense to me at all. The bill was the exact opposite of being fiscally conservative to give away tens of millions of dollars to a company that didn't need it, didn't ask for it. It's fiscally irresponsible to do that.

Petroleum News: You mentioned how you worry about a bad deal coming back your way. A deal that lawmakers deemed bad did come back to the Legislature and it didn't receive a vote under the Stranded Gas Act. You still have that authority, right?

Wielechowski: I view this process we are going through as very, very similar to the Stranded Gas Act. We know what the producers were able to extract back then and I think they will want the same thing this time. We tried to put sideboards on it as far as what deals could be made and what sort of concessions could be given. We've been through this before and it was a catastrophic failure. So I guess you could say maybe this time we'll negotiate a better deal. The problem is you're putting off building a gas line a couple more years. That's the problem. You're going down a path we've already been down, that the people of Alaska — Republicans and Democrats — resoundingly rejected. Here we are going down this path again. Maybe we've got all the time the world. Sure why not? We've tried this. It didn't work. Maybe it's time to try something new.

Petroleum News: Do you think this is the only window?

Wielechowski: I don't think so. If you look at the numbers, there is tremendous growth in Asia for natural gas use. You can't breathe the air in China it's so dirty. I think there will be continued growth. That's what the projections say. If that's the case, we've still got some time. Roger Marks says we've still got a few more years. It's better to wait rather than jump into a bad deal. If you look around the world, there are many other countries and states who are looking at LNG export, so we are not the only game in town. Sitting back and wasting another two years — that concerns me a lot.

Petroleum News: So if it's not the only window, is it the best window?

Wielechowski: Like I said, the governor should put together a team of his top administration officials and business leaders and go out to get contracts.

Petroleum News: Doesn't SB 138 enable him to do some of that?

Wielechowski: I don't think so. What you're doing is you're putting your faith in the oil industry. You're putting your faith in BP, Conoco and Exxon. The administration should be driving the train on this one. I think it's a little backward the way you're doing the pipeline. I think you have a better likelihood of success if you have a state and buyer pipeline. We talked a lot about the Norwegian model. Interestingly the Norwegian government owns 51 percent of the gas line there and I think they own 70 percent of the LNG plant. The state will own 40 percent of 25 percent — maybe. We will be the caboose at the back of the train. Our leg legal attorney testified that's where we'll be also. I don't think that's where the state should be particularly since we've waited for 30 years. We put our faith and trust in these companies for 30 years to build a pipeline and it hasn't happened. I don't have any reason to believe something different will happen this time. That's why I think a different approach where you have the state taking charge and the state going out and making it happen with Alaska taking charge of our destiny.

Petroleum News: You had expressed concerns about the prospects of expansion and how SB 138 doesn't afford for it the way AGIA did. Please talk about that.

Wielechowski: This was an issue raised by our expert Rick Harper. It was one of

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● PIPELINES & DOWNSTREAM

Kinder Morgan faces barrage

Vancouver municipal governments lead regulatory challenges for Trans Mountain expansion; Burnaby would deny services in spill

By GARY PARK
For Petroleum News

Whatever hopes Kinder Morgan had of a smooth passage through the regulatory process with its Trans Mountain pipeline expansion are rapidly disintegrating.

Even with the benefit of new federal legislation that shortens environmental reviews and favorable decisions by Canada's National Energy Board, the C$5.4 billion plan to increase capacity from 300,000 barrels per day to 890,000 bpd is encountering the same headwinds as those that have slowed a final decision on Enbridge's Northern Gateway pipeline.

Kinder Morgan is facing a wall of resistance from the City of Vancouver and the City of Burnaby — two of the largest municipal governments in the Metropolitan Vancouver region — who are challenging the prospect of greater volumes of oil sands bitumen being shipped to a loading terminal, resulting in hundreds of additional tankers operating in Port Metro Vancouver.

Environmental organizations, landowners, business groups and academics have started a constitutional challenge of the new NEB procedures, Vancouver city council is expected to approve a staff report outlining grounds for opposing the new pipeline and Burnaby city council has threatened to withhold emergency services in the event of an oil spill.

That position came just days after the Lower Mainland Local Government Association, representing 33 municipalities and three regional districts, narrowly voted to oppose the proposed pipeline.

Burnaby aid at issue

"The NEB has constitutional power to ram a pipeline wherever they want," said Gregory McDade, from a Vancouver law firm that represents Burnaby in the Kinder Morgan hearings. "But they don't have the ability to compel the city to provide assistance.

"Trans Mountain seems to have assumed in its application that the City of Burnaby would be largely responsible for fire, police, health and emergency services" to aid in the event of a pipeline rupture or spill, he said in regulatory filings.

"However, Trans Mountain has not consulted with or obtained any agreements or service contracts respecting its existing facilities and proposed project and none are contemplated.

"If Trans Mountain does not have a social license and consent from Burnaby, those services may not be made available," McDade said.

The council also said it could refuse to issue road-construction permits sought by Kinder Morgan for ongoing maintenance work once a pipeline was completed.

It said Kinder Morgan had failed to provide a case "as to why expanding the pipeline, tank facilities and marine terminal in a major metropolitan area is the best alternative or in the public interest."

Municipal governments have little power to block the project if it receives federal government approval, leaving the courts as their last resort — an option Vancouver said it will consider to protect the public and city interests.

Company argues minimal impact

The company said the impact of a new pipeline would be minimal because it would be installed on existing rights of way such as power transmission lines, thus minimizing damage to a densely populated area.

"We have a long-standing relationship with the City of Burnaby and have been operating responsibly in the community for 60 years," said Scott Stoness, Kinder Morgan's vice president, regulatory.

The City of Vancouver's staff report said the Kinder Morgan application lacks details, especially relating to health risks and argued that the company's worst-case spill scenarios are not realistic.

According to a poll conducted in January, 48 percent of British Columbians support the expansion and 43 percent are opposed, with 11 percent undecided, up from 3 percent a year earlier.

Courts last resort

Municipal governments have little power to block the project if it receives federal government approval, leaving the courts as their last resort — an option Vancouver said it will consider to protect the public and city interests.

Deputy City Manager Sadhu Johnston told council that Vancouver's efforts spanning many generations to build a green economy could be jeopardized.

He said the NEB review process is stacked in favor of the pipeline and against the public, noting that members of the public who are not listed as interveners can't even file a letter.

In the meantime, the city has filed more than 400 questions, while Burnaby has submitted 1,500 questions of its own. The British Columbia government has added 70 questions.

A spokeswoman for Kinder Morgan said the company does not expect to attract universal support, but remains "committed to the regulatory process and to being open and providing opportunities for community engagement."

The concerns about Trans Mountain's plans extend beyond Canadian borders, with the state of Washington Department of Ecology seeking information on C$750 million in spill liability insurance held by the company.

It has asked the NEB whether Trans Mountain would be liable to the state for natural resource damages and still response costs. ●

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● NATURAL GAS

Donlin applies for gas line right of way

Proposing 315-mile line from Cook Inlet to mine; construction on 14-inch line would begin in 2016, gas delivery in 2019

By KRISTEN NELSON

Petroleum News

Donlin Gold LLC has applied to the State Pipeline Coordinator's Office for a right-of-way lease for a pipeline to take natural gas from Cook Inlet to the proposed mine north of Crooked Creek.

The 14-inch diameter 315-mile line would begin at the west end of the Beluga gas field some 30 miles northwest of Anchorage and end at the proposed Donlin Gold mine site some 10 miles north of Crooked Creek.

The gas line would tie in with the Beluga Natural Gas Pipeline system some 7.7 miles north of the Beluga Power Plant and end at the pipeline terminus metering station at the mine site at milepost 315 of the line.

Permitting is under way for the Donlin gold mine, a project of Novagold Resources and Barrick Gold Corp. A 2011 feasibility study for the mine envisioned a 53,500-metric-ton-per-day mill producing an average of 1.1 million ounces of gold annually for 27 years, with annual production in the first five years expected to be 1.5 million ounces of gold.

A draft environmental impact statement for the mine is expected to be published in August, with a final EIS expected to take about another year, with a decision on the final EIS and accompanying permits slated for the end of 2015.

Gas from Enstar system

"The proposed pipeline would receive natural gas from the Enstar Beluga Pipeline system and transport the gas to an endpoint at the proposed Donlin Gold mine," Donlin Gold said in its right-of-way application.

The line would be able to transport 73 million standard cubic feet per day with a maximum allowable operating pressure of 1,480 pounds psig.

The line would operate at ambient temperature with the exception of the first 10 to 15 miles where the temperature would be slightly higher as the gas transitions from the discharge temperature at the compressor station to the surrounding ambient soil temperature.

Most of the pipeline would be buried, the company said, going aboveground at two active faults. The pigging launcher near Farewell would have supports for the aboveground launcher and receiver. There would also be ancillary aboveground piping and associated valves at 16 remote mainline block valve locations.

There would be no permanent bridge structures, just temporary crossing structures where necessary for equipment during construction.

Horizontal direction drilling would be used at large flow and sensitive habitat river crossings.

Multiple years of construction

The right-of-way application says three to four years of construction would be necessary and temporary support facilities would be required at various points along the 315-mile route, including main camps with communications/tower, pipe storage yards, airstrips, fuel storage sites at airstrips and camps, access roads to material sites, airstrips and water sources and barge landings.

Nine construction campsites would be established during construction, with large 300-person camps moved to support pipeline work and smaller 30-person camps used to support HDD drill crews.

Pipeline construction is planned to begin in approximately 2016, depending on receipt of authorizations. The first year would include pre-construction civil work such as ROW development and construction of access roads. Pipeline installation would take two to three years.

Startup would be upon completion of construction and commissioning of the pipeline, allowing delivery of natural gas to the mine in mid-2019.

Estimated cost for materials, construction and installation of the pipeline project is $1.02 billion; construction and installation of the pipeline, not including the electric transmission line and fiber optic cable and other costs, is estimated at $484.9 million. ●

Contact Kristen Nelson at knelson@petroleumnews.com

LAND & LEASING

State extends terms on 22 Repsol leases

The Alaska Department of Natural Resources extended the terms of 22 Repsol E&P USA Inc. leases on the North Slope in April. The leases are between the Kuparuk River and Colville River units, where Repsol has been exploring for the past three winters. The extensions add four years to the terms of the leases, until dates in May and August 2018.

The leases are between the Kuparuk River and Colville River units, where Repsol has been exploring for the past three winters.

The department also approved a transfer of North Fork unit leases to Cook Inlet Energy LLC, which acquired the southern Kenai Peninsula field in February. The deal involved former operator Armstrong Cook Inlet LLC, Dale Resources Alaska LLC, GMT Exploration Company LLC, Nerd Gas Company LLC and Jonah Gas Company LLC.

In the Interior, Usibelli Energy LLC, Cedar Creek Oil & Gas Co., Windmill Canyon LLC and Arctic Slope Regional Corp. transferred interests to Doyon Ltd. The five companies had previously partnered on an exploration program in the Nenana Basin.

On the North Slope, the state approved the transfer of a 10 percent working interest and 8.3 percent royalty interest in some 20 Royale Energy Inc. leases to Rampart Alaska LLC. Royale and Rampart recently completed a seismic program and now plan to drill.

In the Beaufort Sea, several companies traded interests in BP Exploration (Alaska) Inc. lease ADL 312828, which is part of the Duck Island unit. Doyon Ltd. transferred a 0.067 percent working interest and 0.0536 percent royalty interest in the lease to Chevron U.S.A. Inc. and a 0.433 percent working interest and 0.3464 percent royalty interest to BP Exploration (Alaska). Nana Regional Corp. transferred a 0.2011 percent working interest and 0.16088 percent royalty interest to Chevron U.S.A. and a 1.2989 percent working interest and 1.03912 percent royalty interest to BP Exploration (Alaska).

The state is considering a request from the estate of Robert E. Hickel to transfer small royalty interests in two North Fork leases to Betty J. Hickel, a request from Peter Michael Foley and Melissa McCarty Foley to transfer small royalty interests in six Kitchen Lights unit leases to Shawn Bartholomae and a request from the estate of Doris Ella Bledsoe to transfer small royalty interests in two Redoubt unit leases to Patricia Lynn Bledsoe.

—ERIC LIDJI

● ENVIRONMENT & SAFETY

At what cost for an energy future?

IEA report puts a price tag of $44 trillion on clean energy but says $115 trillion in fuel savings would result; electricity is key

By ALAN BAILEY
Petroleum News

In its Energy Technology Perspectives report for 2014, the International Energy Agency, or IEA, says that the world is not on target to meet needed goals of reducing carbon dioxide emissions from energy production and use, and that an additional $44 trillion in investment is needed between now and 2050 to secure a clean energy future. But the energy transformations resulting from this investment could save $115 trillion in fuel costs, as a result of changes in energy sources and improved energy efficiency, IEA says.

IEA is funded by its 29 member countries and has a role of encouraging dialogue, providing data and making recommendations for ensuring reliable, affordable and clean energy supplies. The agency's perspectives on the world's energy future relate to the Intergovernmental Panel on Climate Change's analysis of future climate change scenarios, based on models which find that human-generated carbon dioxide, if unchecked, will lead to increased global warming.

Changing energy mix

IEA favors a target of reducing carbon dioxide emissions to an extent that would potentially limit future average global warming to 2 degrees C. Under this scenario, electricity overtakes oil products, to become the dominant energy carrier, IEA says. The agency sees natural gas as having a transitional role in replacing more carbon-intensive coal as a fuel for power generation, and in providing flexible power generation to balance the highly variable power output from renewable energy sources such as wind farms.

The agency uses an energy sector carbon intensity index to track worldwide carbon dioxide emissions in relation to the amount of total energy supplied. That index showed a decline of 6 percent between 1971 and 1990 before remaining about constant after that. To achieve the IEA's recommended emissions target, the index must decline 12 percent by 2025 and 64 percent by 2050, with an accompanying slowdown in energy demand, IEA says.

In April the U.S. Environmental Protection Agency said that U.S. carbon dioxide emissions have been falling in recent years, with a 3.4 percent decrease between 2011 and 2012, for example. EPA attributes the fall to a combination of decreased energy consumption, switching of some coal-fired power generation to the use of natural gas, and improved fuel efficiency in the transportation sector.

Need for CCS

The IEA says that a continuing rise in worldwide coal use without the deployment of carbon capture and storage, or CCS, technologies is proving problematic in achieving carbon emissions targets. But high costs and a lack of political and financial commitment hamper the implementation of CCS capabilities, IEA says.

The agency's report says that hydro, onshore wind and solar power development is keeping pace with targets for the management of carbon dioxide emissions, with the cost competitiveness of these technologies improving. Other renewable energy sources such as offshore wind, advanced bioenergy and ocean energy require financial stimuli. Global nuclear power capacity is stagnating.

And the report says that the deployment of renewable energy is accelerating in Asia and emerging economies, while slowing or proving more volatile in Europe and the United States. Progress on the deployment of renewable energy sources depends on government policy incentives. Overall, global investment in renewable energy has declined in the last couple of years, the report says.

The report comments on an increasing use of electric vehicles. China, for example, is trying to improve the air quality in its cities, with an action plan to require nearly one-third of new vehicles in Beijing over the next four years to use electric, hybrid or fuel-cell technologies. The cost of batteries for vehicles is dropping, the report notes.

Energy efficiency

The report stresses the general importance of energy efficiency, saying that industrial plants could over time slash their energy consumption by 11 to 26 percent through the use of best available technologies. However, new and emerging energy saving technologies will require time and investment for commercialization. And a heightened priority for the improved energy performance of buildings is needed, particularly in emerging and developing countries, the report says. The report comments that the United States has introduced new energy-saving building codes.

One area of particular concern for energy efficiency is the rapidly growing array of electrical devices which are continuously plugged into electricity power networks and many of which consume significant power, even when not in active use. One intriguing statistic that the report quotes is the 16,800 gigabytes per second of global internet traffic recorded in 2012, a figure expected to increase to 46,500 gigabytes per second in 2017.

The widespread implementation of technologies to reduce networked device power usage when in standby mode, and to generally improve the energy efficiency of the devices, will require global policy action, the report says. With the number of networked devices in use expected to "skyrocket," energy demand from the devices may reach 1,140 terawatt hours by 2025, the report says. ●

Contact Alan Bailey at abailey@petroleumnews.com

● EXPLORATION & PRODUCTION

Solving the Trading Bay jigsaw puzzle

Hilcorp seeks linkages between complex reservoir sands as part of its efforts to produce more oil from the aging Cook Inlet field

By ALAN BAILEY
Petroleum News

Since taking over a bevy of aging oil fields in Alaska's Cook Inlet basin in 2011 Hilcorp Alaska has made some significant progress in turning around what had been a steady decline in oil production from the basin. During the 2014 Alaska Geological Society Technical Conference, Matthew Frankforter from Hilcorp talked about some of the challenges that the company is dealing with in rejuvenating one of those old fields, the Trading Bay field, offshore in the inlet.

60 wells

The Trading Bay field, discovered in 1965, produces oil both from the Hemlock and the Tyonek formations, within the Tertiary rock sequence of the basin. After years of development, there are now 60 wells penetrating the field reservoirs, Frankforter said. But, to date, only about 78 million barrels of the field's estimated 1 billion barrels of original oil in place has actually been produced, a "pretty low" recovery factor, he said. The production rate from the field has increased about five-fold since Hilcorp acquired the field, he said.

Frankforter said that the primary reason for that low recovery factor is that the field, rather than having major, connected sand reservoirs, consists of a multiplicity of individual sand bodies, with well perforations accessing some of these sands but not others. Currently production comes from about 60 of the 94 identified individual reservoir sands within a 4,000-foot thick, hydrocarbon-rich rock section.

As part of production optimization, Hilcorp is trying to correlate individual sand bodies across the field, to gain an understanding of the past performance of the various well completions and hence to figure out how best to approach future field development. The company is trying a correlation approach that keys into an understanding of the way in which the various rock units were formed.

Currently production comes from about 60 of the 94 identified individual reservoir sands within a 4,000-foot thick, hydrocarbon-rich rock section.

River channels

It has long been understood that the Tertiary rocks of the Cook Inlet were laid down in an ancient land environment, rather than under the sea. And the sand bodies found in fields like Trading Bay represent the in-filled channels of rivers that made their way across the ancient landscape, rather like the nearby Susitna and Matanuska rivers of present-day Southcentral Alaska. During Tertiary times, periods of lush vegetation led to the later formation of coal seams, some of which now extend many miles through the subsurface.

Frankforter said that Hilcorp has categorized the Trading Bay reservoir sand bodies into two types: a Hemlock type and a Tyonek type. The Hemlock type corresponds to a modern-day river that exhibits braided drainage, with several individual channels wending their way along a gravel and sand corridor. The Tyonek type corresponds to a meandering style of river, in which a single channel snakes its way across the landscape. In both reservoir types, the sand and more conglomeratic material that fills the ancient channels typically exhibit excellent qualities as oil reservoirs, Frankforter said.

Modern analogy

There are analogies with a modern river system, such as the nearby Susitna River that drains into Cook Inlet. A braided section of the river, corresponding to the Hemlock reservoir type, might be some four miles across, a size that matches the scale of an oil field such as Trading Bay. A meandering river channel corridor, corresponding to the Tyonek reservoir type, is typically smaller, but could still fit over a field outline, Frankforter said.

But, in addition to the complexities of the sand bodies themselves, the way in which the rock strata in the Trading Bay field have been displaced by a multitude of geologic faults greatly adds to the difficulties of tracing a single sand unit from one part of the field to another, Frankforter explained.

Tracing coal seams

So, rather than trying to track the individual sand bodies, Hilcorp is finding it more productive to trace coal seams across the field, lining up the patterns of coal seams and hence figuring out how the sands between the seams correlate — because of the way in which the coal formed, the coal seams tend to persist across what would have been the wide expanse of terrain within which the smaller river channel corridors lay, Frankforter said. By comparison, the basin, the broad valley, within which the current Susitna River channels lie, is about 65 miles across, he said.

In fact, it appears that the tracing of patterns of coal seams can enable correlations, not just within individual fields but between adjacent fields, Frankforter said.

Hilcorp hopes that these correlation techniques, although still in the conceptual stage, will provide new insights into field-wide reservoir continuity, aiding efforts to improve oil recovery efficiencies and the targeting of undeveloped portions of the field. ●

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● NATURAL GAS

AIDEA studying Cook Inlet LNG plant

The public corporation is considering a proposal to invest in a Greenfield LNG facility that would be tied to Japanese markets

By ERIC LIDJI
Petroleum News

The Alaska Industrial Development and Export Authority is considering a proposal by a Japanese company looking to build a liquefied natural gas export plant in Cook Inlet.

In April, the board of the public corporation unanimously approved a resolution to spend up to $240,000 conducting due diligence on the project, which would export LNG overseas, ship LNG to coastal and road-system communities in Alaska and encourage exploration and production by creating an additional market for Cook Inlet natural gas.

The project sponsor is Resources Energy Inc., an American subsidiary that the Japanese-based Energy Resources Inc. created in late 2011 to pursue an Alaska LNG project in the wake of the failure of the Fukushima Daiichi nuclear power plant. The company has an Anchorage office and has met with state officials, including the now-defunct Alaska Natural Gas Development Authority. Former Alaska Natural Resources Commissioner Dan Sullivan met with company officials during a September 2013 visit to Japan where he signed a memorandum of understanding with Japan Bank for International Cooperation. The agreement "focuses on opportunities for Japanese companies and JBIC to become involved in resource development projects in Alaska — in particular, a large-volume liquefied natural gas pipeline and export facility," Sullivan said at the time.

Although AIDEA had been developing the "B2" pad on the North Slope, the agency recently purchased a pad from Spectrum Alaska LLC to house the plant.

According to an outline of the proposal provided by AIDEA, the goal of the project is to provide additional storage that would help the Alaska energy system better meet peak winter demand, and then to export surplus supplies to the Japanese power market.

The $1 billion project would construct a new 1 million to 1.5 million metric ton per year plant with associated pipelines, marine facilities, loading facilities and storage tanks.

Phase one under way

With the current due diligence effort, AIDEA is considering the basic structure and economics of the project, proposed supply and off-take agreements, potential locations for the plant and the interplay between Japanese and Alaska energy needs. The effort is expected to take 90 days, which would bring it to a conclusion sometime in late July, at which point AIDEA would decide whether to pursue an investment in the project.

This initial phase includes an agreement requiring REI to reimburse AIDEA for 75 percent of the cost of conducting the prefeasibility analysis, up to $180,000. The remaining AIDEA portion would come from money left over from previous projects.

The subsequent phases would focus on crafting appropriate investment arrangements and would likely take another seven months, according to AIDEA, making the entire process of creating and closing the deal take about a year from the initial vote in late April.

Buying Spectrum pad

AIDEA is currently deep into a different public-private partnership to construct a North Slope LNG facility to supply a trucking operation to bring natural gas to the Interior.

Although AIDEA had been developing the "B2" pad on the North Slope, the agency recently purchased a pad from Spectrum Alaska LLC to house the plant. AIDEA made the switch after BP Exploration (Alaska) Inc. said the proposed B2 pad would have created some challenges for establishing fuel connections. The sale gives AIDEA rights to the Spectrum pad, an associated state right of way and key permitting documents.

Spectrum Alaska was one of the three entities that applied to be the private partner in the upstream portion of the Interior Energy Project. AIDEA chose MWH Americas Inc.

FNG splitting supplies

The Interior Energy Project is also funding distribution in the Interior.

Fairbanks Natural Gas recently said it would use a $15 million AIDEA loan to construct distribution lines throughout its service area in Fairbanks this year and next year, but "does not anticipate placing these lines into service" until the entire trucking system is operational, the utility recently told the Regulatory Commission of Alaska. Fairbanks Natural Gas told regulators that it intends to buy 6 million gallons of LNG per year from the North Slope facility. The remainder of its supplies would continue to come from Cook Inlet, through a long-term contract held by its affiliate Titan Alaska LNG LLC.

Referring to the proposed Cook Inlet LNG facility, Fairbanks Natural Gas also told regulators, "This plant could conceivably be located in the Matanuska-Susitna Borough, and could conceivably provide a seasonal LNG supply to the Fairbanks market."

Through its parent company, Fairbanks Natural Gas was the other entity that sought to partner with AIDEA on the North Slope facility. After being passed over in favor of MWH Americas, Fairbanks Natural Gas and its affiliates subsequently abandoned long-running plans to move their entire supply source to the North Slope from Cook Inlet. ●

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GOVERNMENT

Canada in a hurry

Government unveils back-to-back actions to improve safety of overland, tanker petroleum transport; industry to carry cleanup costs

By GARY PARK
For Petroleum News

As the Canadian government faces an early and landmark decision on moving crude bitumen to Asia it is scrambling to win over a hesitant public.

Hard on the heels of new measures to fortify its oil-spill response and tanker safety regime, the administration of Prime Minister Stephen Harper announced tougher regulations for pipelines, hoping to take a "big step" towards meeting the demands of the British Columbia government and First Nations.

The changes will give the National Energy Board greater control over 46,000 miles of federally regulated pipelines that carry more than C$100 billion a year of oil, natural gas and petroleum products within Canada. In total Canada has more than 500,000 miles of pipelines, the bulk under the control of provinces.

Natural Resources Minister Greg Rickford and Transport Minister Lisa Raitt said the NEB will be required to increase the number of pipeline inspections by 50 percent annually and to double the number of safety audits.

Responsibility for cleanups

In addition, the government will impose absolute liability on pipeline companies by making them responsible for cleanups, without needing to be proven negligent or at fault.

Rickford said the pipeliners would need to establish a C$1 billion fund to deal with spills and give the NEB authority to ensure the proper management of cleanups, while the government will cover any accident-related costs that a company is unable to pay, leaving the NEB to recoup that money from the industry.

He also said First Nations will be involved in safety planning and spill response, insisting those communities must play a "key, integral, absolutely critical role" in resource development, estimating that over the next decade 400,000 aboriginal young people will be entering the workforce, creating an unprecedented opportunity to address the need for new workers in the petroleum industry, noting that in 2012 13,500 aboriginal people were employed in the industry.

Not project specific

Rickford denied that the new rules are linked to any specific project, such as Enbridge's Northern Gateway, which faces a critical decision in June by the federal cabinet, insisting they are designed to establish an unmatched regime for pipeline safety.

"Even in the most extreme, rare or unlikely circumstances, the government will ensure that the environment, landowners and taxpayers are protected and the polluter pays," he said, adding "there is no country in the world that transports oil and gas as safely as Canada."

Despite that boast, he said Canada needed to "do more, particularly in the area of liability and compensation to ensure that pipeline operators are fully accountable for their operations in all potential circumstances."

Speaking about the delicate efforts to gain buy-in from First Nations, Rickford also said a strategy will be developed to increase participation by aboriginal communities, along with provincial and territorial governments and the industry to make Canada "a supplier of energy to the world."

Rickford noted that 99.999 percent of oil and petroleum products are safely transported on federally regulated pipelines and the latest measures "aim to improve Canada's record even further."

He said the rate of spills on federally-controlled pipeline in Canada was 57 percent lower than in Europe and 60 percent lower than in the United States over the past decade.

Some BC support

British Columbia Transport Minister Todd Stone would not say whether the proposals, which must still be introduced in the House of Commons, meet the province's criteria for endorsing pipelines, but said they are a "step in the right direction.

"Are we all the way there? I think there's always more than can be done, but what I think is demonstrated by the federal government is a very strong commitment towards ensuring that the standards here in Canada will be world-leading," he said, in by far the most positive indication that the two governments are on track to reach an agreement on oil and LNG export projects.

British Columbia Premier Christy Clark said the announcement shows that the rest of Canada is coming to grips with British Columbia's concerns about heavy oil pipeline development.

"I think having world-leading national standards is a big step," she said, while putting pressure on the Canadian government to ensure it follows through with regulatory details.

"It has been a process of education," Clark said. "British Columbia is a long way from Ottawa (Canada's capital) and it has taken a little bit of time to make sure everybody in the country understands why in British Columbia we are so concerned about protecting our coastline and our land base."

Clark's province is deeply divided over the 525,000 barrels per day Northern Gateway project and Kinder Morgan's application to triple capacity on its Trans Mountain system to 890,000 bpd.

Alberta Premier Dave Hancock said the new rules "strengthen the responsible development of energy resources."

"Every Canadian, no matter what province or territory they call home, expects that energy development is done with a high degree of environmental safeguards," he said in a statement.

There has never been a case in Canada of a pipeline company failing to deal with a spill or rupture and none has exceeded C$1 billion in cleanup costs.

Ziad Saad, vice president of safety for the Canadian Energy Pipeline Association, said the government is taking welcome steps to handle extreme events.

"We are clarifying and strengthening those provisions to ensure the public that they won't be on the hook in case of a pipeline incident," he said. ●

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GOVERNMENT

US Navy deploying Beaufort Sea sensors

During testimony to the U.S. Senate Defense Appropriations Subcommittee on May 14, Rear Adm. Matthew Klunder, chief of naval research for the U.S. Navy, said that in March the Navy had deployed sensors in the Beaufort Sea, offshore northern Alaska, and would be measuring the retreat of summer sea ice. The comment, which came in response to quizzing by Sen. Lisa Murkowski about the Navy's Arctic research, presumably referred to passive acoustic monitors that had been proposed under the Navy's Assured Arctic Awareness Program, a program conducted by the Defense Advanced Research Projects Agency, known as DARPA.

Klunder also said that the Navy will be going to Prudhoe Bay in July to deploy autonomous underwater and surface vehicles to complement the monitoring operation.

Klunder also said that the Navy will be going to Prudhoe Bay in July to deploy autonomous underwater and surface vehicles to complement the monitoring operation.

According to information on the DARPA website, remote sensing "may offer affordable advantages over traditional methods of monitoring the region — aircraft, satellites or manned ships and submarines — due to the great distances in the Arctic."

With ship traffic likely to increase during the summer and commercial activity focused on the seafloor, DARPA plans to develop new technologies for an advanced, distributed sensor system for the year-round monitoring of the Arctic, above and below the ice, to provide situational awareness without the need for a human presence, the website says. The research program seeks advances in sensor systems, to enable station-keeping that is rugged enough to withstand Arctic conditions, is economical to operate and has minimal economic impact, the website says.

—ALAN BAILEY

● FINANCE & ECONOMY

Same range for Brent crude for 10th month

EIA: spot price averaged $108 per barrel in April; average stays between $107, $112/barrel; US crude 8.3M barrels per day

By KRISTEN NELSON
Petroleum News

The Brent crude oil spot price averaged $108 per barrel in April, the 10th consecutive month in which the average price was between $107 and $112 per barrel, the U.S. Energy Information Agency said in its May Short-Term Energy Outlook.

EIA also said new pipeline capacity from the Midwest to the Gulf Coast helped reduce inventories at the Cushing, Oklahoma, storage hub to 25 million barrels by the end of April, the lowest level there since October 2009.

The discount of West Texas Intermediate crude oil to Brent was down. It had averaged more than $13 a barrel from November through January, but fell below $4 per barrel in early April.

U.S. commercial crude oil stocks reached a record high of nearly 400 million barrels at the end of April, which EIA said "is expected to put downward pressure on crude oil prices."

The agency is projecting the Brent spot oil price to average $106 per barrel this year and $102 per barrel in 2015, with the WTI discount to Brent averaging $10 per barrel this year and $11 per barrel in 2015, "reflecting the economics of transporting and processing the growing production of high API gravity (very light) sweet crude oil in the United States."

EIA said the January startup of TransCanada's Marketlink pipeline, moving crude oil from Cushing to the Gulf Coast, along with strong refinery runs, contributed to an increase in the WTI crude oil spot from a January average of $94 per barrel to $102 per barrel in April;

US crude production

"U.S. crude oil production averaged an estimated 8.3 million barrels per day in April, the highest level for any month in 26 years," EIA Administrator Adam Sieminski said in a statement. "EIA expects oil production growth, primarily from increased output in the tight oil formations in North Dakota and Texas, to continue through 2015," he said, with Gulf of Mexico oil production expected to rise both this year and next, "marking the first increase in offshore oil production in five years."

Natural gas spot prices averaged $4.66 per million Btu at Henry Hub in April, down 24 cents from March, and EIA said it projects that spot prices will continue to decline through the spring and summer.

U.S. crude oil production averaged 7.4 million bpd in 2013 and is expected to increase to an average of 8.5 million bpd this year and 9.2 million bpd in 2015, EIA said, with the 2015 forecast of 9.2 million bpd representing "the highest annual average level of production since 1972."

Sieminski said the share of U.S. fuel demand met by net imports reached 60 percent in 2005 and is expected to fall to 23 percent in 2015, "the lowest level since 1970."

The increase in Gulf of Mexico production reflects new wells in the Mars field producing ahead of schedule. Also in the Gulf, production from the Olympus platform and Mars B infrastructure, the first major expansion of the Mars field, is expected to reach 100,000 bpd in 2015.

EIA is projecting U.S. federal Gulf of Mexico production, which has been falling for the last four years, to increase by 150,000 bpd this year and by an additional 240,000 bpd in 2015.

Natural gas

EIA said it expects domestic natural gas marketed production to grow by an average of 3 percent this year and 1.8 percent in 2015.

"Rapid natural gas production growth in the Marcellus formation is contributing to falling natural gas forward prices in the Northeast, which often fall even with or below Henry Hub prices outside of peak winter demand months," the agency said, which may cause some drilling activity to move away from the Marcellus back to Gulf Coast plays where prices are closer to the Henry Hub spot price.

Liquefied natural gas imports have been declining because of higher prices in Europe and Asia, and companies are planning to build liquefaction facilities for export, with Cheniere Energy's Sabine Pass facility expected to be the first to liquefy Lower 48 natural gas for export, coming online in stages beginning in late 2015, EIA said.

Natural gas spot prices averaged $4.66 per million Btu at Henry Hub in April, down 24 cents from March, and EIA said it projects that spot prices will continue to decline through the spring and summer. The agency projects natural gas to average $4.74 per million Btu this year and $4.33 in 2015. ●

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● GOVERNMENT

Proposed refuge regulations raise alarm

Critics say Alaska is unique and should be exempt; CIRI exec relates one driller's struggle with U.S. Fish and Wildlife Service

By WESLEY LOY
For Petroleum News

Alaskans are questioning the need for proposed new federal regulations on oil and gas activity in national wildlife refuges.

The House Natural Resources Subcommittee on Fisheries, Wildlife, Oceans and Insular Affairs on May 20 held a hearing on the matter.

Two Alaskans were on the witness list — Kip Knudson, the governor's director of state and federal relations in Washington, D.C., and Ethan Schutt, senior vice president for land and energy development with Cook Inlet Region Inc.

Both argued against the new regulations possibly coming down from the U.S. Fish and Wildlife Service.

Knudson told the subcommittee that Alaska, which has 16 enormous refuges, should get a "categorical exemption" under the regulations.

Schutt related the case of one driller that encountered all sorts of difficulties in trying to access its prospect in the Kenai National Wildlife Refuge.

The Fish and Wildlife Service manages the refuges.

"There is a long history of private oil and gas development on national wildlife refuges," Steve Guertin, the service's deputy director, said in written remarks to the subcommittee.

Oil and gas development can be found on nearly half of the nation's 562 refuges, Guertin said. The refuge system has about 1,700 active wells, located on just over 100 refuges.

"The service recognizes that private oil and gas rights holders are fully entitled to reasonable access to explore and develop their oil and gas resources," Guertin said.

But better regulations are needed to prevent pollution and other environmental impacts, and to make sure taxpayers aren't stuck with the cost of cleaning up abandoned sites, he said.

Such regulations could "improve regulatory consistency to the benefit of both refuge managers and oil and gas operators," Guertin said.

The Fish and Wildlife Service signaled the potential regulations with its Feb. 24 advance notice of proposed rulemaking.

The subcommittee chairman, U.S. Rep. John Fleming, R-La., said in his opening statement that "no one should be surprised that this administration wants more federal restrictions on our energy industry."

He noted that nearly 70 percent of the active oil and gas wells within the refuge system are in Louisiana.

Fleming said the agency shouldn't duplicate regulatory functions that states already perform. He also said it "must not establish unreasonable new fees" that would have the effect of denying companies access.

Alaska should be exempt from the new regulations for a number of reasons, Knudson said in his written testimony.

Chiefly, a "robust framework" of existing state and federal law already regulates oil and gas development within national wildlife refuges in Alaska, he said.

"This framework is unique to Alaska and was specifically tailored by Congress to provide for the national interest and the economic and social needs of Alaskans," Knudson said.

Two key laws are ANILCA, the Alaska National Interest Lands Conservation Act of 1980, and ANCSA, the Alaska Native Claims Settlement Act of 1971. These laws provide clear guidance for federal management of oil and gas activity in Alaska refuges, Knudson said.

Another subcommittee member, Alaska Republican Rep. Don Young, said in a press release: "The rulemaking proposed by the Fish and Wildlife Service undermines the unique statutory system established in Alaska by both ANCSA and ANILCA, and greatly jeopardizes the process we have put in place to develop our oil and gas resources within refuges. These mineral rights belong entirely to the private land owners and the federal government should not be allowed to impose their burdensome regulations on these areas simply because this administration says so, especially when the states, particularly Alaska, already have robust and effective regulatory regimes to ensure the safe and responsible development of these resources."

The Kenai National Wildlife Refuge is the only Alaska refuge with oil and gas production today. It encompasses Alaska's first big oil field, Swanson River, discovered in 1957.

CIRI owns more than 200,000 acres of subsurface oil and gas interests within the Kenai refuge, Schutt told the subcommittee.

He said the Fish and Wildlife Service's current posture on oil and gas exploration and development in or adjacent to Alaska refuges seems to be: "No. Not here. Not now."

Schutt related the story of NordAq Energy Inc., a small independent with a prospect called Shadura on CIRI-owned subsurface beneath the federally owned surface estate within the Kenai refuge.

To minimize impacts and accommodate the Fish and Wildlife Service, NordAq agreed to build an access road and drilling pad out of ice rather than gravel for its initial Shadura well in 2011. But the agency refused to permit locations in the refuge for drawing water to make the ice road, Schutt said.

"Not easily defeated," he said, NordAq contracted with a fish processing plant in Kenai for truckloads of manufactured ice chips to build the road. Agency staff then raised questions about whether the "imported" ice chips might pose negative effects upon melting.

Subsequently, NordAq has had difficulty securing final agency clearance for "a simple, single-lane gravel road" to develop the apparent gas discovery at Shadura, Schutt said. ●

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LAND & LEASING

Division OKs small expansion at Oooguruk

By KRISTEN NELSON

Petroleum News

The Alaska Division of Oil and Gas has approved a small expansion of the Oooguruk unit on the North Slope, adding some 156 acres within the area of the unit. The acreage is from three small leases that Pioneer Natural Resources Alaska Inc., the former unit operator, acquired in 2012.

Pioneer closed the sale of its Alaska subsidiary, including Oooguruk, to Caelus Energy Alaska LLC on April 15, and Caelus is now the operator.

At the time of the application for unit expansion, Pioneer held 100 percent working interest in the three leases, ADL 392157, ADL 392158 and ADL 392113, all of which carry royalty rates of 16.6667 percent.

In the decision, the division said the proposed expansion overlies a geologic area the division reviewed when it approved the second Oooguruk expansion in 2011.

The division said the second expansion request was "based primarily on the prospectivity of the Torok formation, with additional upside potential within the Kuparuk C and Nuiqsut reservoir sandstones." The division said current Oooguruk production is from the Kuparuk, Nuiqsut and Torok participating areas within the existing Oooguruk unit boundary.

The Oooguruk unit was approved in 2003 and was first expanded in 2007, growing from 20,304 acres on 12 state oil and gas leases to 50,883 acres on 19 state oil and gas leases. Exploration drilling began at Oooguruk, at the northwest corner of the Kuparuk River unit, in 2003; development drilling began in 2007, following installation of facilities and equipment. Production began in 2008 from a six-acre offshore drill site completed in 2006.

Pioneer held 70 percent of working interest at Oooguruk with Eni Petroleum holding the remaining 30 percent.

A second Oooguruk expansion was approved in 2011, adding four leases to the unit. Three leases had previously contracted out of the unit, so after the second expansion there were 20 state oil and gas leases in the unit, which was expanded to 53,188 acres.

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● FINANCE & ECONOMY

Special leases mature into money makers

Net profit share leases in three Alaska North Slope oil and gas units have reached payout status; state collects $61.7M in 2013

By WESLEY LOY

For Petroleum News

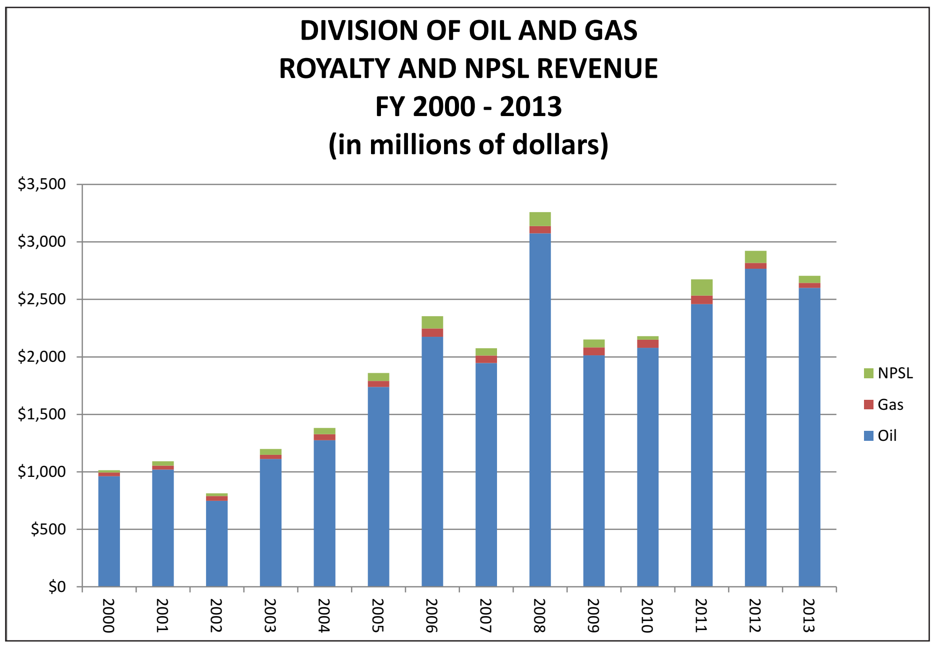
Royalties from oil and gas produced on state leases provide one of Alaska's largest government revenue streams.

A smaller but still substantial revenue stream comes from a handful of so-called net profit share leases.

"These leases provide, in addition to royalty revenues, a percentage of lease net profits after all development and operating costs are recouped," says the new 2013 annual report from the state Division of Oil and Gas.

The state has about 20 active net profit share leases. As of the end of fiscal year 2013, nine had reached payout status, and the state is receiving a monthly payment for its share of the profit, the annual report says.

Active net profit share leases that have reached payout are in the Duck Island, Milne Point and Colville River units on the North Slope.



Serious money

A pie chart in the annual report indicates that in fiscal 2013, the division took in more than $2.64 billion in royalty revenue, while net profit share leases generated about $61.73 million.

The division allocates this and other revenue among various state funds including the general, permanent, school and constitutional budget reserve funds, the annual report says.

Alaska has had net profit share leases since 1979, the University of Alaska Anchorage's Institute of Social and Economic Research said in an April 2006 policy paper.

"Net profit share leases became controversial in 1996 when BP insisted on renegotiating lease terms for its Northstar prospect to eliminate net profit shares, some of which ranged as high as 90 percent, before developing the field," the paper said. "However, BP and several other companies have been producing oil from several North Slope fields with smaller net profit shares — generally 30 percent — for many years without conflict or controversy."

Audits and marketing

The annual report contains other interesting nuggets.

For example, it cites Alaska Oil and Gas Conservation Commission records showing

see **SPECIAL LEASES** *page 16*

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BEAUFORT PLAN

BP made a successful bid of C$1.18 billion for its EL, with the three companies forming their joint venture in 2010.

ConocoPhillips, Chevron and Statoil are also engaged in weighing exploration programs in the Beaufort.

Environmental challenge

Imperial's submission said the co-venturers believe their program can be "carried out in a safe and environmentally responsible manner," a claim that environmentalists are gearing up to challenge, based partly on Imperial's admission that it would be unable to stop an accidental blowout by drilling a relief well within the short summer drilling season.

The proposal now faces a multi-layered screening process that is targeted at starting the two-year drilling program in 2020.

In 2008 and 2009, 3-D seismic programs were conducted by Imperial and BP and over the 2009-11 period the three companies undertook field data collection studies in collaboration with ArcticNet.

The submission said historical data "indicates that the period of manageable ice conditions in the proposed development area is on average about 120 days from May to November."

Imperial said it would use Inuvialuit "expertise and traditional knowledge of the area, particularly their understanding of sea state, ice conditions and wildlife" to build that information into a safe and environmentally responsible program.

One or more wells

The potential drilling schedule allows for one or more wells to be spudded in EL 477, assuming the joint venture can achieve a number of objectives including commitments in 2016-18 to a drilling system, including an array of ice-breaking support vessels.

If no further drilling is planned after the exploration well or wells once the two ELs have been drilled, the shore-based facility at Tuktoyaktuk could be returned to its pre-program condition and all remaining supplies, equipment and fuel would be shipped out of the Inuvialuit Settlement Region unless other arrangements were made.

The submission said the program design would draw on 90 years of experience by Imperial and ExxonMobil in working "safely and responsibly during drilling and production activities in the Arctic and global experience in operating in harsh offshore environments."

Imperial reiterated that its "primary approach to well control is prevention."

It said procedures would ensure that wells were "designed for the range of risk expected," that equipment was inspected and maintained, operators were trained, tests and drills were conducted to verify personnel competence and that "adequate barriers and redundancy" were in place and tested to safely execute the work.

For the Beaufort, contingency plans would be developed for emergency response and oil spill response.

"Surface intervention would be the primary means of regaining well control and the fastest method to put in place," the submission said. "Other effective same-well intervention methods including activating the subsea (blow-out preventer) stack, which is typically the first option for regaining well control."

Drilling system evaluation

The project description said a number of drilling systems are being evaluated, including jack-up rigs, moored semi-submersible drilling units and drillships.

For water depths and conditions likely to be experienced in the Beaufort, a "floating drilling unit is the system of choice."

Imperial said a key requirement of any drilling system is its ability to maintain its position at the well site locations, using either a moored drilling system that has anchors attached to the seafloor or a dynamic position using a computer-controlled system to automatically maintain the drilling unit's position and heading by using its own propellers and thrusters.

Whatever drilling system is selected, it will "use proven technologies appropriate for the most severe conditions that could be experienced," the submission said.

Multiple vessels would support the program, including support and supply vessels, fuel tankers and an ice-strengthened wareship (which would serve as an alternative supply base for a remote operation), all of them powered by diesel engines burning low sulphur diesel.

Imperial said the drilling unit and support vessels could mobilize from either Vancouver or Prince Rupert on the British Columbia coast, or from a port on Canada's East Coast via the Northwest Passage. ●

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continued from page 1

OFFICIAL RESIGNS

of directors and to lenders back in January that had aimed "to revitalize the stock and pay off the company debt," but that new board members "elected to pursue a different course and removed me from the CEO position. Since that time they have pursued liquidation of assets as an alternative. Since those decisions were made I have not been in a position to alter the course of the company nor contribute in any meaningful way to the ultimate fate of the organization." Responding to the letter, Buccaneer said it "does not authorize this communication in any way."

After his suspension, in March, Burton filed suit against the company, claiming that he had been terminated against the terms of his employment contract. The court recently stayed the case and required the two sides to enter arbitration, according to Buccaneer.

Buccaneer said it has "no current intention" to replace Burton as chief executive officer and managing director, but the board said it intends to continue working with its Chief Restructuring Officer John T. Young Jr., of Conway Mackenzie Inc., to determine how best to restructure the company to meet its financial commitments.

—ERIC LIDJI

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INTERIOR BASINS

Sediment filled basins

The Nenana basin is one of several sediment-filled basins, formed by the pulling apart, or "rifting," of the Earth's crust in Alaska's Interior.

Doyon Ltd., the Native regional corporation for the Interior, has been spearheading the exploration of two of the basins, the Nenana basin, southwest of the city of Fairbanks, and the Yukon Flats basin, to the city's north. Both basins show broadly similar geology, containing huge thickness of non-marine sediments with abundant coal seams, Richter said. An analysis of gravity data has indicated maximum basin depths of 20,000 to 25,000 feet, with seismic data for the Nenana basin supporting this depth determination, he said.

Doyon's exploration program has included the recent drilling of the two deep Nenana basin wells, the Nunivak No. 1, drilled to 11,100 feet in 2009, and Nunivak No. 2 well, drilled to 8,667 feet in 2013. The basin is shaped rather like a northeast-southwest oriented dog bone, with the two wells being drilled in the narrowest part of the bone shape, near the village of Nenana, Richter said. The No. 1 well was drilled quite close to the fault that marks the eastern boundary of the basin, near the village of Nenana, while the No. 2 well was drilled farther to the west.

Nenana rock sequence

The shallowest and youngest of the sequence of sediments in the Nenana basin consists of 3,000 to 4,000 feet of gravel, washed down from the Alaska Range in Pliocene and recent times, Richter said. Under these gravels lies the Usibelli group, a sequence of sediments, Miocene in age and of interest from the perspectives of both coal and petroleum potential. Beneath the Usibelli group is an unconformity, a break in the sequence of sediment deposition, below which are sediments of Paleocene age.

Both of the Nenana basin wells penetrated a sand unit called the Suntrana sand within the Usibelli group. This sand, 500 to 700 feet thick and with excellent hydrocarbon reservoir potential, consists almost entirely of quartz grains where it was encountered by the No. 2 well. But, where penetrated by the No. 1 well, the sand contained more rock fragments, a phenomenon that presumably reflects the relative proximity of the basin margin, Richter said.

The Suntrana sand exhibits porosities in excess of 20 percent, even at depths of 7,000 to 8,000 feet, he said.

Gas saturation

A rock sequence of particular interest within the Usibelli group lies deeper than the Suntrana and is called the Healy Creek formation, a formation that includes sand bodies 70 to 80 feet thick, shale horizons and coal seams, Richter said. Sands of this formation found at the bottom of the Nunivak No. 2 well showed a porosity of 20 percent or more, with uniform gas saturations of 25 to 30 percent, he said, adding that the reason for this uniform distribution of low gas saturation within the sand remains something of a mystery.

The level of gas saturation was presumably too low to constitute a commercial discovery. But the gas was found to be very "wet," containing sufficient natural gas liquids to yield some 15 to 30 barrels of liquids per million cubic feet of gas, Richter said. The hydrocarbons had clearly migrated from a source rock and were clearly "thermogenic," formed from the action of subsurface heat on organic debris rather than from bacterial action, Richter said.

Oil potential

And, in terms of potential oil and gas sources, the wells encountered coals and shales with high organic contents, with these rocks also exhibiting high hydrogen contents appropriate to potential oil generation. One shale penetrated by the No. 2 well was 120 feet thick, with a total organic carbon content of 5 to 6 percent, Richter said. Laboratory testing of samples of potential source rocks obtained from the drilling demonstrated the potential generation of gas and medium to light oil, he said. And the geochemical analysis of lake bed samples from the region showed hydrocarbon signatures characteristic of natural gas liquids.

Evidence of the subsurface temperature history of the rocks suggests that the top of the "oil window," the depth range within which heat might have generated oil, would be about 12,000 feet in the middle of the basin, rising to about 8,000 feet towards the basin margins, Richter said. And a basin analysis has suggested that the potential source rocks could have generated a very large volume of oil, he said.

The interbedding of sand and shale strata, in conjunction with faults known to cut the basin, provides many opportunities for the trapping of generated hydrocarbons, he said.

Although coal-bearing, terrestrial sediments are more commonly associated with the formation of natural gas than oil, there are known oil-bearing coal deposits, Richter said. For example, a coal source is associated with some known oil seeps in Southeast Alaska, and a major oil basin in Australia has coal and shale as oil sources, he said.

Yukon Flats

The Yukon Flats basin, to the north of Fairbanks, actually consists of several sub-basins, Richter said. Doyon has conducted both a 2-D and a 3-D seismic survey over one of these sub-basins, the sub-basin in the area of Stevens Village. Seismic data elsewhere in the basin are old and sparse. The geochemical analysis of lake-bed sediments indicates that the Stevens Village sub-basin may be oil prone. However, analysis of similar sediments in proximity to another sub-basin, the Birch Creek sub-basin, suggests that this basin may be more prospective for gas, Richter said.

In 2013 Doyon said that its sees the potential for a major oil find in the Yukon Flats basin, and that it is using its 3-D seismic data from near Stevens Village to identify potential drilling targets. The corporation also said that it hopes to conduct further seismic surveying in the Nenana basin in the winter of 2014-15. ●

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LINC JV

said. With a gas drive installed, the company believes the well would produce as much as 2,000 bpd.

Shortly after the test, Linc said it intended to develop the field and began conducting early engineering and permitting for surface facilities, pipelines and roads. But the Umiat field is notoriously remote, even by Alaska standards, and bringing it into production would require significant infrastructure investments. The state has expressed an interest in building a road to Umiat to encourage investment, but the effort has been stalled.

—ERIC LIDJI

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WIELECHOWSKI Q&A

the biggest issues when we were doing AGIA. The way it is now there will be tremendous impediments to expansion by the state. I think it's unlikely the producers will have incentive to expand. The state will have huge incentive to expand. The problem with the way it is now, the state will have to put up huge capital to expand at a time when we are bleeding a couple of billion dollars a year. I think that's a problem. I think rolled in rates would have been a better approach. Rolled in rates is a presumption with FERC. I think it was a big mistake not to have a provision there. The other concern I have is in-state gas, just the ability to draw enough gas out of that pipeline at a price that is economical for Alaskans. That has not been adequately addressed.

Petroleum News: So what is your solution toward affordable in-state gas?

Wielechowski: My solution has always been you build a pipeline from Cook Inlet up to Fairbanks. Shoot, we could do that and have it built in two years. It does two things. It gets gas to Fairbanks and the Interior very quickly and the second thing it does is it encourages more exploration in Cook Inlet. The problem with Cook Inlet is you find a huge amount of gas and you have no market for it. This would add a fairly large market.

Petroleum News: If you build a pipeline to Fairbanks, what about industrial use, like for the mines?

Wielechowski: You could also use it for industrial use. Cook Inlet, according to the USGS, has 19 trillion cubic feet of gas. That's an enormous gas field. The 95 percent confidence covers 7 trillion cubic feet. That's enough to last us for decades. The tax structure in Cook Inlet is a negative tax before you factor in everything. Cook Inlet is underutilized and it's still a tremendous, tremendous gas asset for the state.

Petroleum News: You were probably most vocal about Richard Rabinow not being allowed on the board. You were pretty steadfast about this, six months after he was appointed. How come?

Wielechowski: We've had an Alaska law on the books for decades that these boards and commissions positions are supposed to be filled with Alaskans. I envision the AGDC board as a policy board; they are setting the big overarching policy on how this gas line is going to go forward. I think you are better served by having people who live in the state, who work in the state, who understand the state's needs, someone who will fight for lower in-state gas prices and lower tariffs.

Petroleum News: He is still only one of five voices and could be overruled?

Wielechowski: That's true, but I think it's the message that could be sent to Alaskans. If it could be one on this board well we saw the governor try to appoint someone from out of state to the SARB board, which was equally concerning. It's a dangerous, dangerous road to go down. Yes, it's one this year, but it could become a few more next. If you want people who work in the oil industry we've got people who worked in the oil industry capable of doing that.

Petroleum News: Even got someone from Alaska who worked for an oil company, you could still argue that person has the company's interests at heart, don't you think?

Wielechowski: That's true. I want to see who the appointee is. That's the problem we had with Bernie Washington. In his case he worked for the industry for 36 years fighting that entire time or at least a huge chunk of time fighting for a lower tax. I said this on the floor, Bernie Washington I would have approved him for just about any other appointment but a guy who spent most of his career fighting for low tariffs; his task is to get fair tariffs, particularly after what happened with the firing of Marty McGee. You have to take it as a whole. That firing of an imminently qualified assessor with strong Alaskan roots fired for no other reason other than he had been fighting for a fair assessment against what the oil industry wanted. You've got to put everything in perspective.

Petroleum News: Was the law changed to accommodate AGDC?

Wielechowski: Oh absolutely. The bill was introduced in the Rules Committee on the House side. How often do you see that happen? We pushed confirmations back one week. The governor quickly signed it. He didn't put out a press release.

Petroleum News: So what took the minority so long to provide pushback on this?

Wielechowski: I think we were offering pushback all along. When you look through the appointees, it just has the town and people saw Houston, then thought Houston, Alaska. When appointees come out, I don't think there are too many legislators who go out and check where everybody lives. All it had was Richard Rabinow, Houston. It just wasn't something you historically see. We expected the governor to follow the law.

Petroleum News: The debate over the new oil tax regime under SB 21 is heating up again as we approach the repeal vote in August. ConocoPhillips recently reported stronger earnings on less production. What does that tell you?

Wielechowski: It's a data point to look at. In my opinion this goes back to a duty to produce. We've gone down the path of asking the wrong questions for years now — the attorneys who represented the state for years. The question isn't how much can they make somewhere else. The question is, are they making a reasonable profit here in Alaska. They have a contractual obligation under the terms of their leases to produce if they can make a reasonable profit based on hurdle rates and internal rates of return. You know the returns on the legacy fields are staggering. You're not competing anywhere else. Even if you were, you had much higher rates of return than North Dakota, Canada and even Eagle Ford. The question isn't, are we competitive with places compared to other parts of the world. The question is can they make a reasonable profit. The answer is yes.

Petroleum News: What are your thoughts on the administration permitting oil industry to pay the lower amount of appraised property value until the appeals have been exhausted?

Wielechowski: I'm a property tax payer here in Anchorage. I can't imagine a leader in our community, if you are disputing your property tax, you don't have to pay the higher rate. That's in inappropriate move in my opinion. There is a process to follow in how much you pay. If you disagree, there is a process. For an executive just to go out and change the rules for one particular player is very disturbing. Every TAPS valuation has been litigated for several years. You've got a Supreme Court ruling now. They can litigate every single one of them if they want. I can't imagine the Supreme Court coming to a different conclusion than the one they reached a couple of months ago. I think it's a pretty strong precedent that has been set by the Supreme Court. ●

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SMALL EXPANSION

In the current expansion approval the division said Oooguruk and the expansion area contain the Jurassic Nuiqsut sandstone, one of three oil-bearing intervals within the Jurassic Kingak formation; the Kuparuk C sandstone; and the Torok formation.

The most recent Oooguruk production figures from the Alaska Oil and Gas Conservation Commission are for March. In that month, Oooguruk averaged 7,343 barrels per day, 624 bpd from the Kuparuk formation, 6,295 bpd from the Nuiqsut formation and 424 bpd from the Torok.

Cumulative production from the Oooguruk unit through March was 15.4 million barrels, 8 million of that from the Kuparuk pool, 6.7 million from the Nuiqsut pool and 0.7 million from the Torok pool.

The division said exploration within the proposed 156-acre expansion area will be under a plan of development. Current activities are being conducted under the seventh POD, which expires Aug. 30. A proposed eighth POD is due to the division June 1. ●

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JOBS OUTLOOK

Tesoro, Doyon, ASRC Energy Services, ConocoPhillips and Carlisle Transportation.

Alaska's 'renaissance'

"Alaska's oil and gas industry is undergoing a renaissance," state Labor Commissioner Dianne Blumer wrote in an introductory letter. "Favorable market conditions, well-timed and properly structured incentives, and a fair tax structure focused on new investment have all contributed to a business climate that encourages new investment."

"Favorable market conditions, well-timed and properly structured incentives, and a fair tax structure focused on new investment have all contributed to a business climate that encourages new investment."

Blumer continued: "Across the state we see increased exploration, reinvestment in legacy assets, and development of new fields like Point Thomson, the Colville Delta, and the Greater Mooses Tooth unit. These investments mean opportunity and jobs for Alaskans."

The plan updates the "Alaska Oil and Gas Strategic Training Plan" published in 2008. The new plan expands the industry definition to include downstream sectors such as pipeline transportation, refining and related construction and manufacturing.

"This definition of the industry compels a more expansive examination of the industry's workforce composition, future workplace demand, and the supply of potential workers to fulfill those needs," the new plans says.

Since the 2008 plan was published, the overall trend for oil and gas employment has been upward, the Department of Labor says.

"Economic factors, aging oil fields and infrastructure, development of smaller satellite fields, and more challenging exploration characteristics have contributed to this trend of increasing employment, despite declining oil production in the state," the plan says.

Replacing baby boomers

A big challenge for the energy and mining industries nationally is age. About a third of the U.S. workforce is composed of baby boomers poised to retire by the end of this decade. This situation is reflected in Alaska's oil and gas workforce.

A "notable paucity" of oil and gas workers age 30 to 45 was apparent in Alaska's workforce by 2011, the workforce development plan says.

Age information is not available for all Alaska oil and gas workers. Using the Alaska Permanent Fund dividend database, however, the Department of Labor is able to get a good handle on the resident workforce.

Seven out of 10 workers in the Alaska oil and gas industry were Alaska residents in 2011, the plan says.

"In total, 6,566 resident workers (32.4 percent) are likely to reach retirement age within the next five to 10 years," the plan says. "Taking into consideration the high level of earnings, physical demands, and operating environment common to the industry, the average retirement age is estimated at 58 years."

Hot jobs

Oil and gas offers some of the highest paying jobs in the state. Average annual earnings for the industry exceeded $120,000 in 2011, the plan says.

"Of the 216 occupations for which the Alaska mean wage is available, chief executive officers, engineering managers, commercial pilots, chemical engineers, lawyers, geoscientists, and other construction and engineering managers earn the highest wage in the Alaska oil and gas industry," the plan says.

A Department of Labor analysis showed that "an estimated 2,000 new workers will be needed by the Alaska oil and gas industry between 2010 and 2020 as a result of growth. An estimated 5,500 will be needed to replace workers who retire or otherwise leave the industry."

The industry steering committee determined the workforce development plan should focus on occupations needed for exploration and production. While the industry's development and construction needs remain important, the scale of most development projects likely to occur during the planning period "will most likely be accommodated by the existing workforce."

The plan adds: "Large-scale projects, not yet fully sanctioned, are likely to occur outside of the current plan."

These major projects, all potentially huge job creators, include a pair of proposed trans-Alaska natural gas pipelines, and the Donlin Gold mining project, which could draw Cook Inlet gas for power.

The industry steering committee determined five occupational groups will be in high demand over the next five years: engineering; the geosciences; health, safety, security and environment; maritime; and remote sensing and inspection.

This last one is being driven in part by the maintenance demands of aging oil fields.

Dirty work

Of course, producing oil and gas in Alaska requires more than the guys in suits and offices.

In terms of total worker count, the Department of Labor in 2011 found that roustabouts topped the list of Alaska oil and gas occupations with more than 1,500 workers.

A roustabout, according to the Schlumberger's online oilfield glossary, is "any unskilled manual laborer on the rig site."

Roustabout is among positions in the industry that see a lot of turnover. The workforce development plan says that between 2010 and 2020, we'll see 315 roustabout replacement openings.

Turnover projections for other positions such as drillers, unit operators, petroleum engineers and refinery operators can be found in the plan.

The plan also includes a sweeping overview of the many educational and apprenticeship opportunities available to prepare people for work in oil and gas and related fields.

Two programs of note are ANSEP, the state university's Alaska Native Science and Engineering Program; and APICC, the Alaska Process Industry Careers Consortium, which has people from companies such as BP, ConocoPhillips, Shell and Alyeska Pipeline on its board of directors. ●

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SPECIAL LEASES

that 150 development and service wells and 21 exploration and stratigraphic test wells were completed in Alaska during the 2013 fiscal year. The annual report also notes that the division gained authority in 2003 to audit lessee royalty and net profit filings.

"Since then, 60 audits have been issued and an additional $156.3 million in state revenue has been collected as a result," the report says.

The audits examine volumes and values, as well as costs claimed as deductions.

"Because a royalty filing provides information at a summary level, it is important to audit the details that support the filing to ensure that royalties and net profit share payments have been correctly calculated, reported and paid," the annual report says.

"In conducting an audit, an auditor may look at oil and gas valuation, costs associated with the transportation of oil and gas, and exploration, development and production costs."

A table near the back of the annual report summarizes the enormous volumes of undiscovered, technically recoverable oil and gas believed to remain in Alaska, including its outer continental shelf.

Part of the division's job is reaching out to companies and investors.

"Much of this effort has been conducted in Houston, Texas, targeting both U.S. and international companies ranging in size from small independents to supermajors," the annual report says.

The division participates in major conferences such as NAPE, the North American Prospect Expo. ●

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