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page 3 Q&A: DNR commissioner describes LNG project enabling legislation

January Mining News inside

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

Canada untroubled by LNG rivalry

The prospect of Canada competing against itself in the global LNG market has yet to set off alarm bells in the British Columbia or federal governments.

But the topic is about to get tested before Canada's National Energy Board, which has applications from Oregon LNG and Jordan Cove LNG to import a combined 2.83 billion cubic feet per day from Western Canada as feedstock for their two LNG projects in Oregon.

That comes on top of seven permits approvals by the NEB for domestic LNG operations that represent a total of 14.7 bcf per day of gas supplies, with two more Canadian applications filed for a combined 3.4 bcf per day.

see **LNG RIVALRY** *page 13*

BP expects diverse energy future, mix of oil, gas, coal, renewables

Alaska could be facing some tough competition.

Global energy consumption will slow and diversify over the coming two decades as demand rises in emerging economies, according to the BP Energy Outlook 2035.

The fourth edition of the annual forecast presents a world where technology is scrambling the global energy trade. Unconventional oil and gas are tilting the balance of supplies toward North America and improved efficiencies are slowing demand.

Those changes would have big implications as Alaska looks to sell its oil and gas.

Oil growth to slow

Oil loses market share in the forecast, growing at just 0.8 percent per year.

see **BP OUTLOOK** *page 19*

LAND & LEASING

It's still flawed

9th Circuit sends 2008 Chukchi lease sale appeal back to district court

By ALAN BAILEY
Petroleum News

The U.S. Court of Appeals for the 9th Circuit has found that the environmental impact statement, or EIS, for the 2008 federal oil and gas lease sale for the Chukchi Sea outer continental shelf is flawed. In a court order dated Jan. 22 the court remanded the document back to the federal District Court for Alaska for further action. The absence of a legally valid EIS renders the lease sale itself invalid unless, presumably, the deficiency in the environmental document is corrected.

In a majority opinion, a panel of three 9th Circuit judges ruled that the Department of the Interior had inappropriately used an estimate of 1 billion barrels of economically recoverable oil in assessing the potential environmental impacts of the lease sale. This estimate of recoverable oil was "arbitrary and capricious" the judges said.

One judge dissented, saying that he defers to the expertise of the Bureau of Ocean Energy Management, or BOEM, the federal agency responsible for outer continental shelf leasing, in making the 1 billion barrel determination.

Exploration started

Shell, ConocoPhillips, Statoil and other compa-

see **LEASE SALE APPEAL** *page 20*

ENVIRONMENT & SAFETY

Getting cleaner

Environmental monitoring shows pollution from oil terminal, tankers is declining

By WESLEY LOY
For Petroleum News

An ongoing scientific study offers positive news about the impact of oil shipping on waters at Valdez and beyond.

The study is known as the long-term environmental monitoring program, or LTEMP.

It involves sampling sediments and mussels for signs of oil pollution. The sampling sites begin at the Valdez Marine Terminal, where tankers load Alaska North Slope crude oil, and range across Prince William Sound and the Gulf of Alaska to Kodiak Island.

"Based on the sediment and mussel data, petrogenic hydrocarbon inputs from the Alyeska Marine Terminal and tanker operations continue to

> *"Based on the sediment and mussel data, petrogenic hydrocarbon inputs from the Alyeska Marine Terminal and tanker operations continue to decline," concludes an LTEMP report covering the years 2008 through 2012.*

decline," concludes an LTEMP report covering the years 2008 through 2012.

Petrogenic means hydrocarbon compounds associated with petroleum.

The reasons

Within Port Valdez, the decrease in oil pollution

see **LTEMP** *page 18*

GOVERNMENT

Legislature in session

Parnell calls for state ownership in gas line; approval process will be more open

By KRISTEN NELSON
Petroleum News

The Alaska Legislature gaveled in Jan. 22. In Gov. Sean Parnell's state of the state address Jan. 23, and the Democratic response which followed, gas pipeline issues were highlighted as significant for the session, and party lines on the issue appeared drawn.

GOV. SEAN PARNELL

The governor, a Republican, emphasized the value of state equity participation in the Alaska LNG Project, the big line the producers and TransCanada are working on to take North Slope natural gas to Cook Inlet for liquefaction and sale aboard.

On the gas pipeline issue, House and Senate minority leaders cautioned against giving away the state's resources.

Governor's view

Parnell noted "historic progress" made recently on the gas line, with "all the necessary parties" aligned for the first time: the North Slope producers, TransCanada, the Alaska Gasline Development Corp. and the departments of Natural Resources and Revenue.

Because of the complexity of a liquefied natural gas project, the state hired experts to look at the

see **STATE OF THE STATE** *page 19*

contents

Petroleum News *North America's source for oil and gas news*

● GOVERNMENT

Balash describes enabling legislation

DNR commissioner talks about what Legislature will be asked to approve to allow state's equity participation in Alaska LNG project

By STEVE QUINN
For Petroleum News

Joe Balash hasn't been commissioner for the Department of Resources very long, slightly longer than two months. But his frontline experience in the state's efforts to advance a natural gas pipeline runs deeper than most in Alaska.

1 2 SERIES

Balash has been on a legislative or executive branch staff since Gov. Frank Murkowski's administration attempted to secure a contract with North Slope producers ExxonMobil, ConocoPhillips and BP in 2006.

Balash worked for the Legislative Budget & Audit Committee for two years while the Legislature reviewed Murkowski's contract under the Stranded Gas Development Act.

He then worked for former Gov. Sarah Palin as a special assistant on energy issues, particularly the Alaska Gasline Inducement Act, one of Palin's signature pieces of legislation.

Gov. Sean Parnell retained Balash, but as a deputy commissioner working under Dan Sullivan. He oversaw the divisions of Oil and Gas and Geological and Geophysical Surveys as well as the Mental Health Trust Land Office, the State Pipeline Coordinator's Office and the Gas Pipeline Project Office. He was also a member of Gov. Parnell's gas-line team.

But last fall Balash found himself working as acting commissioner while Sullivan accepted a deployment assignment with the U.S. Marines, a prelude of the job he now has. On Nov. 13, not long after Sullivan's resignation to pursue a seat on the U.S. Senate, Balash became commissioner.

Balash is now busy preparing to work with the Legislature in pursuit of statutory changes that support recent gas line agreements with TransCanada, ExxonMobil, ConocoPhillips, BP and the Alaska Gasline Development Corp.

The state signed two agreements, known as a memorandum of understanding, MOU, and Heads Of Agreement, HOA.

Balash sat down with Petroleum News to discuss the agreements and what he believes can be done this session to advance a project featuring a large-diameter line running from the North Slope to a liquefied natural gas plant in Nikiski.

Petroleum News: Let's start with the session. What do you want from lawmakers to advance a gas line project?

Balash: In broad terms there are things that we need for AGDC, things that we need for the Department of Natural Resources and things that we need for the Department of Revenue. With regard to AGDC, we are going to ask the Legislature to establish a subsidiary to carry the state's interest in the large project. That way we can maintain very clear missions and objectives for each organization and not have competing claims for resources or personnel, and we need to make clear that the subsidiary can in fact own liquefaction.

HB4, when originally set up to imbue AGDC with all of its powers, was relatively silent on the matter of liquefaction and so you can take a liberal view of their authority to say, 'well if they are not prohibited of course they can because they can own things.' Or you can take a very conservative view and say, 'if it doesn't give them the power, they don't have the power.' That will become really important at the time when underwriters get involved and there are financings being undertaken. We want to go ahead and make it very clear now that in fact a subsidiary can in fact carry in interest in liquefaction.


JOE BALASH

Petroleum News: So why doesn't DNR carry that interest, or even DOR?

Balash: Because DNR is and will remain a state agency with day-to-day duties to carry out the management of the state's resources. Same is true for DOR. It makes a lot of sense for there to be a specific corporate entity to carry out these interests. Now, going back to the legislation, we need the authority for DNR, in consultation with DOR, to negotiate agreements with the companies. Those agreements need to go upstream to the producers and downstream to the service providers. As far as the state's equity position goes, our royalty rates are pretty well set out in the lease and unit agreements, but we do have a couple of instances where we have a net profit share lease or a sliding scale royalty where it really would make sense to flatten the royalty for those properties. Now, that doesn't mean everything just goes to the lowest number but we will arrive at some point in between. Let's say you have a sliding scale that starts at 12.5 and goes up to 20. It doesn't mean we will wind up with a single royalty rate of 12.5 or a single royalty rate of 20. We will probably land somewhere in between. But we will fix it so that we can very clearly identify the state's royalty interest as a matter of the equity gas. We need the authority to amend those leases, amend those agreements in that way.

For the Department of Revenue, in order to establish the equity interest in the gas that is represented by production tax, we need to move away from a net tax to a gross tax and then allow a taxpayer to pay that tax in gas. By taking that approach, we arrive at a fixed number for each property. Those fixed numbers then are what represents the state's overall equity position, first in the gas but then gets carried through each of the components of the project. The state's revenue will be derived from the sale price of the LNG. That is the legislation in a nutshell. The contracts we are asking the authority to negotiate are contracts that, if they are going to be long-term in nature are going to need legislative approval. The ones that matter, the ones that affect the state's bottom line in the long term are the ones that will have to come back to the Legislature at a later date.

Q AND A

Petroleum News: Do you have a sense of a timeline for this project?

Balash: Where the project is now, they have begun some of the pre-FEED (front-end engineering and design) activities. Assuming we are successful in the legislative arena, the project sponsors would execute the pre-FEED agreements. That process would be completed, taking 12-18 months. So that would take us from the second quarter 2014 into 2015, somewhere between second and fourth quarter and pre-FEED would be completed. We would be developing the contractual agreements both upstream and downstream during that period, then bringing them forward publically for review and ultimately for legislative approval. I would think most likely we would be looking at a special session during the fall of 2015. But if things took a little bit longer, it's conceivable things could drift into 2016.

The idea would be that action would move us from pre-FEED into FEED. That would take us into 2017 or 2018. After FEED, would come FID — final investment decision. Construction would take, depending upon a couple of things, four to six years. We would be looking at first gas somewhere in the 2022-2025 timeframe. The shorter each of these phases takes, the sooner we get gas to Alaskans.

One of the things I think is going to be most telling, and we'll get a start on this year — again, assuming success from the Legislature — we will get a sense of the market from the buyers of LNG just how much appetite they have for Alaska LNG. There are a lot of things that we think add up to make this a very competitive project in the portfolio of supply that's out there competing for those buyers. Until we actually start that process, we won't know for sure.

That's one of the things is contained in the Heads Of Agreement. The producer parties will initiate marketing efforts during this phase of development. That's important for a number of reasons. A number of parties in Asian markets, especially in Japan, have heard about Alaska in the past. They may have heard it from a variety of voices. This is going to be one of the first times they will have heard about the possible delivery of Alaska LNG from the producers.

We've gotten some feedback from various parties, even some of our own contacts, that Alaska LNG is not part of what's being marketed by these companies right now. They are offering LNG for sale, obviously, but it's from places other than Alaska. One of the important things to us in the development of this Heads Of Agreement was the clear demarcation of the marketing to begin.

Petroleum News: There are some familiar features of this plan and the Stranded Gas Act. Among several things, both have the state taking an equity stake; both have the state taking royalty in kind; both have private negotiations, based on regulatory guidelines that get presented to the lawmakers. Are you going back to the Murkowski deal?

Balash: No. Absolutely not.

I would distinguish this from that effort in a number of ways. The first is the transparency here. We are stepping forward

see BALASH Q&A page 15

● NATURAL GAS

LNG project works from Thomson to inlet

ExxonMobil Alaska LNG project manager tells Alliance 'project management at this early stage is all about managing uncertainty'

By KRISTEN NELSON
Petroleum News

The "heads of agreement" announced by Alaska Gov. Sean Parnell Jan. 10 at the Alaska Support Industry Alliance's Meet Alaska conference may not be the silver bullet the Alaska LNG Project needs, but it's "pretty close to it," Steve Butt of ExxonMobil, senior project manager for the project, told the conference later that same day (see story on governor's announcement in Jan. 19 issue).


JUDY PATRICK

STEVE BUTT

"The one thing that we have today that we've never had before is everybody working together," Butt said.

The Alaska LNG Project consortium includes BP, ConocoPhillips, ExxonMobil and TransCanada.

Butt said he thinks that having the state in the project "sets the stage for the success of this project."

The state's participation is subject to legislative approval of the heads of agreement the governor announced, and the memorandum of understanding between the state and TransCanada, transitioning from the license TransCanada holds under the Alaska Gasline Inducement Act into a commercial arrangement.

Significance of Point Thomson

Butt said his Alliance talk was essentially an update from the presentation he gave at the Resource Development Council's annual conference in November (see story in Dec. 8 issue).

He highlighted work ExxonMobil has under way at Point Thomson, which is scheduled to begin life producing oil. But the pad design at Point Thomson will accommodate facilities needed later for natural gas production, he said.

The work to put in liquids production facilities at Point Thomson is "a huge accomplishment," Butt said, "but it's only the first step — because the real value of Point Thomson is the gas."

> *The 8 billion cubic feet of natural gas at Point Thomson is important to the Alaska LNG Project because "it provides economies of scale."*
> **—Steve Butt, ExxonMobil**

The 8 billion cubic feet of natural gas at Point Thomson is important to the Alaska LNG Project because "it provides economies of scale," he said. "LNG is all about cost," he said, telling the audience that purchasers don't care where they get LNG — they just don't want to pay anymore than they have to.

"And the way we drive our cost down is through economy of scale."

Having natural gas from Point Thomson as well as Prudhoe Bay is important because once the infrastructure is built, putting more gas through it makes the project more efficient, Butt said. "And if I'm efficient, then I win," he said, because in a commodity business, "low cost wins."

The Cook Inlet end

At the other end of the project, in Cook Inlet, there are a lot of questions remaining, Butt said.

"We're not sure where or if we need to cross the Susitna; we're not sure where we want to cross the Cook Inlet."

He said it's important to get those things right to put the pipe in the right place "to provide gas to Alaskans," but also to drive project costs down. The range has been put at $45 billion to $65 billion, and Butt said it's important to get the cost to the low end to keep the project competitive.

Laying pipe across Cook Inlet isn't that difficult, "we lay pipes across a lot of lakes ... and rivers all over the world."

"It's how you enter the water and how you exit the water that's really a challenge," he said.

Onshore the project is looking at a site by the ConocoPhillips' plant in Nikiski. Butt said the new liquefaction facility will be 15 to 17 times as large as the existing LNG plant.

That site was selected because it's favorable for construction, and also favorable from a marine perspective.

The project is also "continuing to look at the plant itself: what's the right technology" to chill the gas.

"It's very simple to make gas smaller when you make it cold," Butt said, referring to the liquefaction process, but, he said, "it is very complex to do that with three and a half billion cubic feet of gas a day coming off the North Slope."

The regulatory framework underpins project work, he said, adding that "project management at this early stage is all about managing uncertainty. If you put your buyer's hat on and you think, 'I'm risking my economy for 30 years and putting my children's and my grandchildren's standard of living in your hands,' we've got to do it right."

The regulatory framework is important in making the project work, Butt said.

The project has already spent some $175 million gathering data between Prudhoe and Livengood, and moving into the 2014 field season, "it's all about trying to figure out the southern route."

With the Alaska Gasline Development Corp. working with the Alaska LNG Project, "we'll be able to look at opportunities to maybe collaborate there; it opens a lot of doors for us."

A strong fiscal environment is important, he said, and the project needs "the Legislature to take a hard look at this" in this year's session. ●

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● NATURAL GAS

Demand driving Interior Energy Project

The leaders of the public-private partnership are looking at Fairbanks North Star Borough distribution as they make decisions

By ERIC LIDJI
For Petroleum News

When it comes to Alaska energy policies, the conversation is usually about supply or transmission, but the Interior Energy Project is shaping up to be largely about demand.

The success of the state-backed effort to bring North Slope natural gas to the Interior by late 2015 depends in large part on whether government and industry can expand distribution in the Fairbanks North Star Borough and convince consumers to connect.

In late December, the Regulatory Commission of Alaska gave the Interior Alaska Natural Gas Utility a certificate to serve much of the borough because the municipal utility promised an ambitious timetable to build out distribution lines. In mid-January, the Alaska Industrial Development and Export Authority chose MWH Americas Inc. to be its partner on a North Slope liquefied natural gas facility largely because the deep pockets of the global infrastructure would allow more public dollars to go toward distribution.

Downstream

The RCA decision favored access over experience.

While the Interior Gas Utility counts many experienced business leaders among its board, it is a relatively new entity. The three local governments in the Fairbanks North Star Borough created the utility in late 2012 as an alternative to Fairbanks Natural Gas LLC.

The privately held Fairbanks Natural Gas currently serves a small customer base in the city of Fairbanks, but also wanted to expand into less populated corners of the borough.

The two utilities presented two "very different worldviews" over the months of deliberations, according to a statement from RCA Commissioner Robert Pickett.

"Driven by traditional, private sector sustainable economics," as Pickett phrased it, Fairbanks Natural Gas would give only a general sense of its schedule for building out distribution. The company estimated the amount of pipeline it expected to lay by 2021, but CEO Dan Britton said any actual decisions would depend on economics. "I think that's really the only way a system can be built out," he testified during hearings.

Utility economics consider both supply and demand — the fixed costs of acquiring a commodity and the ways to spread those costs across all customers — and the RCA ultimately rejected the Fairbanks Natural Gas proposal because it relied too heavily on the electric utility Golden Valley Electric Association as an industrial anchor.

The Interior Gas Utility, on the other hand, committed to reach 80 percent market penetration among the homes and businesses in the higher density sections of its service area by 2021, which Pickett called "a huge task to accomplish in a very tight timeframe" and "unprecedented for any natural gas utility in Alaska" and possibly the country.

The utility could tackle this challenge because it is motivated by the twin goals of reducing energy costs and improving air quality, rather than by economics. Its financing would come from grants, bonds and tax exemptions afforded only to municipalities.

"State support will be necessary for the build-out to occur in the less economic areas of the community," the Interior Gas Utility told the RCA during the deliberation process.

While the RCA decision focused on demand and scheduling, RCA Commissioner Paul Lisankie believed it should have focused on Senate Bill 23, which in May 2013 made $332.5 million available to the Interior Energy Project through grants, loans and bonds.

The financial package "reflected a broad consensus (which nothing in our long hearing caused me to question) that obtaining natural gas and distributing it throughout the Fairbanks North Star Borough could not be done without substantial subsidies," he wrote.

Even though the RCA rejected the Fairbanks Natural Gas request, it encouraged the private utility to expand within its existing service area as supplies become available.

Commissioner Norman Rokeberg put an even finer point on it. While voting for the Interior Gas Utility, he praised Fairbanks Natural Gas for the "innovation and entrepreneurial risks" it took to bring gas to Fairbanks in the first place. Should Fairbanks Natural Gas someday saturate its existing service area and the Interior Gas Utility flounder, Rokeberg wrote, Fairbanks Natural Gas should take another stab at expansion.

Upstream

While the downstream decision depended on the responsibilities unique to the public sector, the upstream decision depended on the possibilities unique to the private sector.

All three proposals before the Alaska Industrial Development and Export Authority met the primary goal of Interior Energy Project: to bring natural gas to the Interior at half the cost of fuel oil by late 2015. With a 9 billion cubic foot per year plant, the average household would save $2,795 per year under the MWH plan, $2,829 under the Pentex Alaska Natural Gas Co. LLC plan and $2,883 under the Spectrum Alaska LLC plan.

With such a tight spread, the decision came down to other factors.

The Spectrum proposal included different technical specifications than the other two. It promised to provide the cheapest gas to consumers, but raised safety and reliability concerns for AIDEA. The proposal also featured the highest rate of return for any of the projects and shifted some risk to AIDEA if the project failed to materialize as intended.

The Pentex and MWH proposals were technically similar, but their financial structures differed greatly. The $175 million Pentex proposal used a $35 million grant from AIDEA, a $110 million loan from the AIDEA-administered Sustainable Energy Transmission and Supply Development Fund, the minimum $20 million contribution in private equity and $10 million in private debt. The $185.5 million MWH proposal also used a $35 million AIDEA grant, but only $68 million from SETS and made up the remainder using $28.9 million in private equity and $53.6 million in private debt.

The Interior Energy Project included $125 million in SETS loans. So while the Pentex proposal set aside $15 million for distribution, the MWH proposal set aside $57 million.

Connecting the pieces

That ultimately made the difference, but another factor may have also come into play.

Pentex is the parent company of Fairbanks Natural Gas and made its ability to handle the upstream and downstream components of the complex project one of its selling points.

The RCA decision upended that advantage. The hearings became so contentious that the RCA ruling scolded the Interior Gas Utility for its attacks on Fairbanks Natural Gas.

While saying that Pentex is already "actively involved" in expanding distribution in the Fairbanks North Star Borough through its Fairbanks Natural Gas subsidiary, the AIDEA report comparing the proposals noted "MWH is well-suited to working with all utilities."

The Interior Gas Utility recently "engaged" MWH to "assist in planning and development of the new utility's storage, regasification and distribution facilities," AIDEA wrote.

The AIDEA timeline calls for signing a project development agreement with MWH by mid-March. Among other things, the agreement would start bringing all the parties to the table to get a better sense of how the upstream and downstream components would relate. ●

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● ENVIRONMENT & SAFETY

'Sink-or-swim' debate rages on

Canadian government report on what would happen if diluted bitumen spilled in ocean fails to resolve feud over dangers of exports

By GARY PARK

For Petroleum News

The debate over what happens to diluted bitumen, dilbit, from the Alberta oil sands when it spills in ocean water was unresolved by a Canadian government technical report.

The confusion spawned by those findings do nothing to help or hinder plans by Enbridge and Kinder Morgan to open export routes to Asia through their Northern Gateway and Trans Mountain pipeline projects to Pacific Coast tanker ports.

And the report has done nothing to deter a coalition of three environmental organizations from taking their fight against Northern Gateway to the Federal Court of Canada.

Karen Campbell, a staff lawyer for Ecojustice, which is representing the three groups, said December's joint report by the National Energy Board and Canadian Environmental Assessment Agency recommending federal government approval of Northern Gateway subject to 209 conditions was based on insufficient evidence and failed to comply with a legislated requirement of the environmental review process.

The conditions ordered research on how dilbit would behave in a marine environment.

She said the review panel "did not have enough evidence to support its conclusions that the Northern Gateway pipeline would not have significant adverse effects on certain aspects of the environment."

Enbridge responded that the review process was the "most thorough and comprehensive proceeding in Canadian history," overriding any need to delay a federal government decision pending the court challenge.

Campbell said the action would not have been filed "if we didn't think we had a fighting chance."

Duration of exposure a factor

Separately, the collaborative dilbit report by branches of Environment Canada, Fisheries and Oceans Canada and Natural Resources Canada said the question of whether dilbit spilled in a marine environment would float or sink depended on the duration of the exposure to a number of natural processes.

The basic conclusion was that dilbit, like conventional crude, would float on salt water and sink in waves when mixed with fine sediments.

The study found that a commercial chemical dispersant, Corexit 9500, had quite limited effectiveness in dispersing dilbit.

The bitumen displayed some of the same behaviors as conventional petroleum products (such as fuel oils and conventional crudes), but also presented significant differences, notably for the rate and extend of evaporation.

The 88-page report, still regarded as an interim finding, determined that dilbit can sink if it mixes with sediments in the water and is pounded by waves.

In 2010 about 843,000 gallons of dilbit spilled from an Enbridge pipeline in the Kalamazoo River in Michigan — the largest onshore spill in North American history.

Much of that crude was sopped up, but 15 to 20 percent mixed with sediment and sank to the river bottom. ●

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● FINANCE & ECONOMY

India getting serious

Oliver, Redford, meet with government, energy officials in New Delhi, Mumbai; no deal yet, cut Oliver says it could be substantial

By GARY PARK

For Petroleum News

India and Canada are once more, after a decade of blowing hot and cold, on the brink of doing a deal over oil and natural gas investments.

Indian government sources say state-owned refinery Indian Oil Corp., IOC, will conclude a deal to buy a 10 percent stake in British Columbia 449 trillion cubic feet of Montney shale gas assets held by Malaysia's Petronas by mid-March, while the Alberta government's petroleum marketer has signed a tentative agreement to ship oil sands bitumen to India.

ALISON REDFORD

A long history of on-again, off-again negotiations showed their best hope yet in mid-January as Canada's Natural Resources Minister Joe Oliver and Alberta Premier Alison Redford, plus teams of officials, met with Indian government and energy officials in New Delhi and Mumbai.

The reason for these high-level contacts was evident in BP's annual global energy outlook, which forecast India's energy demand could rise 135 percent by 2035, outpacing other members of the BRIC partnership — Brazil, Russia and China — by a wide margin.

JOE OLIVER

Imports of oil to the subcontinent will grow 169 percent and of natural gas by 573 percent.

Over the past decade, various Indian state-owned companies have raised hopes of multibillion-dollar infusions into Canada's energy sector, peaking in 2012 with word that a trio of companies was on the verge of bidding C$5 billion for ConocoPhillips oil sands properties.

By some estimates, India has invested US$100 billion in global oil and natural gas assets over the past two years.

No guarantees yet

"Nothing is guaranteed but I'm hoping we'll see some substantial investments," Oliver said in a Jan. 15 conference call from Mumbai. "And you know when they come they're likely to be substantial."

He said that optimism is based on talks with senior executives in India's Ministry of Petroleum and Natural Gas, plus the stable of companies — IOC, ONGC, Essar Oil, Reliance and H-Energy (which is involved in an LNG export project in Atlantic Canada).

Oliver said the issue for India is whether "they can get projects built giving the rising costs of oil sands facilities and get the bitumen delivered top India within a particular time frame."

But he stressed that the companies are uneasy about regulatory delays in building pipelines to the Atlantic and Pacific coasts.

Redford said India's refinery operators are especially interested in the prospect of importing oil sands bitumen and in becoming strategic partners in developing the resource.

To that end, the "arrangement" between IOC and the Alberta Petroleum Marketing Commission, although "very preliminary," could see Canada positioned to export its first crude by 2017-2018, assuming one or all of Enbridge's Northern Gateway, Kinder Morgan's Trans Mountain expansion and Transcanada's Energy East gets

see **GETTING SERIOUS** *page 8*

● GOVERNMENT

AOGCC hears comments on frack regs

Oil industry expresses concerns about need, cost and practicality; environmentalists say rules don't go far enough to address issues

By ALAN BAILEY
Petroleum News

Having published a third draft of its proposed new regulations governing hydraulic fracturing in Alaska, on Jan. 15 the Alaska Oil and Gas Conservation Commission, or AOGCC, held a public hearing to listen to public comments on the draft regulations. During the hearing, Kara Moriarty, president and CEO of the Alaska Oil and Gas Association, an Alaska oil industry trade association, said that, while the members of her organization support reasonable regulation, the member companies also worry about the potential cost to the industry of implementing the regulations.

"Absent further changes, the proposed regulations will result in substantial costs that could cause some wells, especially in the Cook Inlet, to be adversely affected and thus frustrate the development of overall production in Alaska and production in an area that's vital to providing necessary natural gas for the residents of Southcentral Alaska," Moriarty said.

Barrett Ristroph, Arctic program representative for the Wilderness Society, presented comments from a number of environmental organizations and particularly focused on concerns about the need for public information about chemicals in the fluids used for hydraulic fracturing, should these chemicals stray into people's water supplies.

"We believe that chemical information is really critical to allow health professionals and emergency responders to make the accurate diagnoses that they need to make proper treatment," Ristroph said.

Not new in Alaska

Oil companies have been conducting hydraulic fracturing in wells in Alaska to stimulate oil production from oil fields since the early days of the oil industry in the state. But the recent upsurge in the use of the technique for shale oil and shale gas development in North America has led to a parallel upsurge in concerns about the potential environmental risks associated with the technique. AOGCC rules for assuring safety in hydraulic fracturing operations are embedded in the commission's current regulations. But, with the future possibility of shale oil development in Alaska, and with several states developing new regulations for shale oil and gas development, AOGCC is developing specific regulations for hydraulic fracturing in Alaska.

And, having now reached the third draft of those regulations, the commission says that it may adopt the regulations, with or without further modification, or that it may decide to take no further action.

The proposed regulations include: notification of landowners, surface owners and operators within one-half mile of wellbore trajectory; pre and post hydraulic fracturing water well water sampling and analysis; disclosure of chemical makeup of hydraulic fracturing fluids; wellbore integrity; containment of hydraulic fracturing fluids; and casing and cementing.

Unsubstantiated concerns

In written testimony to AOGCC, the Alaska Oil and Gas Association said that unsubstantiated public concerns were triggering the promulgation of new hydraulic fracturing regulations in a number of states. The association cited several studies conducted by organizations such as the Environmental Protection Agency and the Groundwater Protection Agency, researching whether hydraulic fracturing poses any environmental threat.

"To put it quite simply, these studies have found that hydraulic fracturing, particularly as it is implemented in Alaska, does not pose any harm to the environment," the association wrote.

Moriarty, in her testimony, commented that well water sampling requirements in the proposed regulations are significantly more stringent than in other states and could, without risk, be made less onerous.

"In Alaska fractures are targeted at areas thousands of feet below any freshwater aquifers" and pose no risk to Alaska's water resources, Moriarty said.

Moriarty also requested that public reporting of hydraulic fracturing information be done through a system called FracFocus that is used in the Lower 48, and not through some dual system developed for Alaska. She also raised some questions over the potential for inconsistencies in some of the water testing results — there are no Alaska facilities capable of doing some of the testing required, she said. In addition, some of the regulations relating to the notification of any environmental contamination require clarification, she said.

Saying that there is a lack of information about the impact of fracking on Alaska rock formations, Bob Shavelson, executive director of Cook Inletkeeper, a Cook Inlet-based conservation organization, argued for more research into the environmental effects of hydraulic fracturing. Shavelson said that people in the area of the Kenai Peninsula where he lives, an area with active gas drilling, worry about the possible contamination of water wells.

Trade secrets

Ristroph questioned a provision within the proposed regulations that would allow companies to exempt from public disclosure information that they view as constituting a trade secret. This issue particularly arises in relation to chemicals used in hydraulic fluids — companies may view some of the chemicals that they use as providing a competitive advantage in their fracking operations.

Rebecca Noblin, Alaska director for the Center for Biological Diversity, also picked up on the trade-secrets issue.

"Fracking poses a danger to public health and the environment and if it's allowed the public must be granted full

see **FRACK REGS** page 9

continued from page 6

GETTING SERIOUS

government approval.

The commission currently markets 70,000 barrels per day of conventional crude and 300,000 bpd of bitumen that the government receives in lieu of cash royalties.

Test shipment in November

India's Oil Minister M. Veerappa Moily told reporters Jan. 14 that his country is exploring ways to add Canada to the list of countries that qualify to provide feedstock to India's state-owned refineries, which import 80 percent of their annual crude requirements of 4.32 million bpd.

India has asked Canada to create a national agency to execute term deals.

IOC has already tested its ability to process Canadian crude by receiving a shipment in November of 1 million barrels from Newfoundland's offshore White Rose field, which Oliver said could set the stage for exports from the Energy East pipeline's terminal in Saint John, New Brunswick.

He said Canada is hoping the larger export volumes would involve heavy crudes, which Indian refineries are equipped to process "economically." ●

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● EXPLORATION & PRODUCTION

BP president: more Prudhoe development

Says new drilling rigs, drilling programs will add jobs and create more production; pleased with state involvement in LNG project

By ALAN BAILEY
Petroleum News

Commenting that Alaska is the only one of 13 oil and gas producing U.S. states not to see a production increase in response to high oil prices in the past couple of years, BP Alaska President Janet Weiss told the Alaska Support Industry Alliance Meet Alaska conference on Jan. 10 that BP "is committed to playing an important role in Alaska's energy renaissance." BP and its partners want to play their part in trying to turn the state's oil production decline into an increase, she said.


JANET WEISS

"We invested 12 percent more in 2013 than we did in 2012," Weiss said. "Our plans call for 40 percent more in 2014 than we spent in 2013."

Weiss also commented that the state's decision to participate in a liquefied natural gas project, to market North Slope gas, would facilitate commercial alignment in the project and would become an important consideration in the business case for project continuation.

"We are really pleased at BP with the State of Alaska's decision to participate as an equity owner, a partner," Weiss said.

Tax reform

Weiss attributed BP's resurgence of interest in Alaska oil development to the reform of the state's oil production tax, enacted during the last legislative session. Under the new oil tax BP plans to re-invest nearly 90 cents of every dollar that the company makes in Alaska over the next five years, she said. This represents a 60 percent increase in investment, compared with what happened during the previous tax regime, she said.

"I'm talking about projects that will play a substantial role in supporting Alaska's economy for decades," Weiss said. "Oil and gas development is one of the most effective engines for generating jobs in the Alaska economy."

Weiss said that BP's initial focus is on light oil, which she characterized as the "bread and butter" of the oil industry and the resource that provides the economic foundation for the more challenging North Slope resources such as heavy oil and liquefied natural gas.

New investment

"We and our working interest owners at Prudhoe Bay will increase our production generating investments by $1 billion over five years, including adding two new drilling rigs, starting in 2015," Weiss said.

The additional rigs will increase BP's North Slope rig fleet size to nine rigs, compared with just five rigs in 2012. That will result in an additional 30 to 40 wells being drilled each year, she said. And each new rig directly adds around 200 new jobs to the Alaska economy, she said.

A potential $3.2 billion of additional investment by the Prudhoe Bay working interest owners can result in 118 new wells; the first new Prudhoe Bay well pad in more than a decade; the expansion of two existing pads; and the debottlenecking of some facilities in the western part of the field. There is the potential for 200 million barrels of new oil resources, adding 40,000 barrels of oil per day to the throughput in the trans-Alaska oil pipeline, Weiss said.

Sag River

A production opportunity that is gaining momentum is the development of the Sag River formation, a thin and technically challenging oil reservoir above the main Prudhoe Bay reservoir, Weiss said. BP has conducted some field tests in this formation, trying out some new techniques that may reduce development costs.

"This play is very development cost challenged," Weiss said.

Following some successes in the play, BP is moving forward with a 16-well program scheduled for 2015 and 2016, with the ultimate possibility of 200 new wells and perhaps 200 million barrels of new oil, she said.

BP is also considering some new viscous oil development in the northwest Schrader area of Milne Point, an area where BP is a 100 percent working interest owner. That development would require $1 billion to $2 billion in investment, with the potential to bring 80 million barrels of new oil on line while creating hundreds of jobs. But the viability of this project will require some new technology advances, Weiss said. ●

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continued from page 8

FRACK REGS

access to the data so as to prevent or avoid those harms as much as possible," Noblin said.

Commission Chair Cathy Foerster commented that there are existing state statutes for resolving trade secrets claims.

Saying that there are many issues associated with fracking, including the emission of dangerous air pollutants; water pollution; the consumption of large quantities of water and high rates of natural gas leakage, Noblin told the commissioners that the Center for Biological Diversity favors a complete ban on hydraulic fracturing in Alaska.

"In other words, the practice that's been going on for 40 years we should now ban?" asked Commissioner John Norman.

"Correct," Noblin replied. "We're looking for a ban on the practice of hydraulic fracturing, because of all the dangers associated with it." ●

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● GOVERNMENT

State says new tax is fiscal neutral

At anticipated oil prices both ACES and MAPA tax system would raise similar revenues; other factors caused revenue forecast to drop

By ALAN BAILEY
Petroleum News

With opponents of the State of Alaska's new oil production tax characterizing the tax change as a $2 billion giveaway, the debate over the tax is heating up ahead of an August referendum on whether the tax change should be repealed. But the state remains adamant that, far from being a giveaway, the change is essential to the encouragement of new investment in the Alaska oil industry and, hence, to the industry's health.


BRUCE TANGEMAN

The change involves replacing the previous tax system, known as ACES, by new tax rules under the More Alaska Production Act, or MAPA, sometimes also referred to as Senate Bill 21.

The state's latest revenue forecast for fiscal year 2014 shows a revenue decline bearing an uncanny resemblance to that $2 billion figure, although the new tax law only comes into effect for part of that year. But at prevailing oil prices the new tax has almost no revenue impact, Bruce Tangeman, deputy commissioner of the Alaska Department of Revenue, told the Commonwealth North Energy Action Coalition on Nov. 17.

Lower prices, higher expenditure

The biggest single factor, by far, in the reduced revenue estimate is a lower expectation for oil prices, based on current price trends, Tangeman explained.

"That's what we saw was happening," Tangeman said. "The prices were flattening and going down a bit."

The second biggest factor in the reduced revenue forecast is a growth in the expected oil industry expenditures on the North Slope, expenditures which are deductible from a company's taxable income. These expenditures, which in part reflect new announcements about oil-field activities, including the bringing of additional drilling rigs to the Slope, will be beneficial for oil industry jobs and oil production — the goal is to put money into the private sector for hiring people, rather than into the state's coffers, Tangeman said.

Lower production

Next comes a reduction in the estimate for the amount of oil likely to be produced — less oil translates to less state revenue. The reduction in the oil production forecast results from the state trying to take a more conservative and hence a more realistic view of future production, with assumptions that not all possible future oil development will take place as planned — past state production predictions have tended to be over optimistic and have been wildly inaccurate, Tangeman said.

In future the state expects its production forecasts to be closer to reality than they have been in the past 20 years, he said. And the production figures used in the new revenue forecast do not reflect any possible production uptick that might result from the new tax regime, he said, adding that the state is going to take a closer look at the production forecast when it prepares its spring revenue forecast.

"While we're showing a more conservative line, we're also recognizing there's a tremendous upside," Tangeman said. "But when legislators and the executive branch sit down and look at what they have to budget with, we think it's important for them to have a more conservative and realistic goal."

Other items

Another chunk of the revenue drop comes from an accelerated closeout of some tax credits left over from the ACES system. Royalties, property tax and corporate income tax are also expected to drop.

That leaves a small anticipated production tax drop in financial year 2014 as a consequence of the new tax law and a tax rise of about $50 million in 2015 as a result of the tax change, Tangeman said.

And estimates of likely annual state revenues under ACES and MAPA for financial years 2014 to 2017, using oil prices in the range $105.86 per barrel in 2014 to $110.38 in 2017, shows almost no difference between the likely revenues emanating from the two tax systems.

"$2 billion — it's not even part of the equation," Tangeman said.

Progressivity

The key differences between the two taxes are the base tax rates and the progressivity, the way in which tax rates rise with rising oil prices. ACES has a base rate of 25 percent of net income, which applies at relatively low oil prices, but with rates becoming progressively higher at higher prices. MAPA, on the other hand, has a fixed base rate of 35 percent at all price levels, albeit with a lower rate that would apply to some newly developed oil.

> *But at prevailing oil prices the new tax has almost no revenue impact, Bruce Tangeman, deputy commissioner of the Alaska Department of Revenue, told the Commonwealth North Energy Action Coalition on Nov. 17.*

Thus, at low oil prices the tax take from ACES, at 25 percent, would be lower than the take from MAPA, at 35 percent. At high oil prices, as progressivity kicks in, the rate for ACES would become higher than that for MAPA. The cutover point, at which the ACES tax take starts to exceed that of MAPA, occurs at an oil price of around $105, Tangeman explained.

ACES disappointment

Tangeman said that a sharp decline in oil production, rather than a predicted trend towards flattening, after ACES went into effect, had been a motivation for the state to change the tax system. And that higher than expected decline came despite the fact that oil prices that had increased substantially, rather following a predicted somewhat level trajectory. The unexpected oil price increase should have triggered a boost to production, not an accelerated decline, Tangeman said.

And Tangeman explained that one problem that the state had identified with the ACES system was the way in which the tax progressivity — the change in tax rate with the oil price — caused major fluctuations in the effective tax rate from one month to the next, as the oil price fluctuated. Short term fluctuations in the effective tax rate make it very difficult for oil companies to plan investments, he said. For example, in 2009, a year for which the state has verified tax records and a year with big oil price swings, the effective tax rate varied between 50 percent in July and 15 percent in December, he said.

Under the new system the tax rate is completely predictable, Tangeman said.

"That's one of the biggest changes that we're seeing," he said. ●

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● EXPLORATION & PRODUCTION

Husky joins Statoil in leaning east

Symonds says opportunities in Atlantic region offshore could be better than prospects in Northwest Territories Canol oil shale

By GARY PARK

For Petroleum News

Husky Energy has echoed Statoil, its senior partner in offshore Newfoundland plays, in suggesting the East Coast is a better bet than Western Canadian prospects.

Norway's Statoil indicated it is leaning more towards Newfoundland and away from the Alberta oil sands, while Rob Symonds, Husky's senior vice president for Western Canada production, suggested opportunities in the Atlantic region are better than his company's prospects in the Canol oil shale in the Northwest Territories.

A joint venture of the two companies is faced with increasing pressure since reporting three breakthrough discoveries in the Flemish Pass basin over the past four years, with the latest boosting overall estimates to about 540 million barrels.

Statoil and Husky are now trying to line up a rig for a delineation well at their Harpoon discovery for which they have yet to issue a recoverable resource estimate.

Although the Bay du Nord success lags behind the potential of the oil sands or even the Canol, the dilemma for the companies is based on soaring costs in Canada and worldwide and weighing the comparative costs of separating crude from oil sands bitumen and extracting oil from the remote NWT play, or securing deepwater rigs for Newfoundland.

Statoil is expected to decide between the two in March, while Husky, backed by growing offshore experience in the South China Sea, is faced with deciding whether to enlarge its core operations in North Atlantic waters.

Flemish Pass success

Symonds, speaking to a BMO Capital Markets conference in New York in January, said the company's "real success" in Atlantic Canada has been the deepwater Flemish Pass.

The company's current output in the shallower waters of the Jeanne d'Arc basin is about 50,000 barrels per day from the White Rose project that it operates and its minority stake in Suncor Energy's Terra Nova field.

Symonds said Husky does have "some exploration opportunities" in the White Rose field that could add to those volumes.

He told analysts the three discoveries, in which Husky has a 35 percent stake, "are themselves sufficient probably for a deepwater development," with timing likely in the range of 2019-2021.

White Rose also offers a natural gas prospect, which the Canada-Newfoundland and Labrador Offshore Petroleum Board has rated at 3.02 trillion cubic feet, although the region has been unable even when gas prices were robust to figure out an economic way to get the gas to market.

The regulatory board has attached a figure of 12.19 tcf to discovered gas resources in the Newfoundland-Labrador region.

Symonds doubted that commercializing White Rose gas is likely to happen before 2020.

Husky evaluating Canol

Meanwhile, Husky is evaluating its Canol tight oil prospect along with one in the Muskwa formation in northwest Alberta.

The challenge for the Muskwa is to find an economic means of developing the Duvernay-equivalent rock, while the Canol shale faces its own difficulties, he said.

Symonds said the Bakken has 5 million barrels of oil in place for every 640 acres, while the Muskwa has 20 million barrels and the Canol shale could have 80 million-90 million barrels but is restricted to a three-month "working window in the winter."

Even though an all-weather road has been built to open up the summer season, he said, "the real challenge for us is: What is the type curve? Can we afford to build the infrastructure ... to go to year-round activity?"

Husky and other Canol operators are exploring information sharing to avoid repeating mistakes, but Husky is holding back from drilling after two vertical wells established hydrocarbons in the region, Symonds said.

He said horizontal wells might be drilled in the 2015-2016 winter, "allowing us to make a long-term determination of deliverability. It's the logistics of a long-term test that are holding us back."

In weighing the rival prospects within the company, Husky views the chances of offshore Newfoundland development by 2020 as more attractive than Canol development, Symonds said. ●

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● GOVERNMENT

BP: More miscible injectant not economic

Company tells AOGCC separation equipment required to produce more MI for enhanced oil recovery without loss of natural gas liquids

By KRISTEN NELSON
Petroleum News

The Alaska Oil and Gas Conservation Commission has been investigating whether maximizing production of natural gas liquids for shipment down the trans-Alaska oil pipeline, which the commission ordered in Conservation Order 360 in the mid 1990s, is in conflict with the production of miscible injectant, used for enhanced oil production.

Following a 2012 hearing on Prudhoe Bay propane, held after Harold Heinze questioned whether there was waste because propane was not being produced for sale, the commission found that propane was not being wasted, but it understood BP witnesses at that hearing to say that more miscible injectant, MI, was needed and it has been investigating that issue.

One premise of CO 360 was that there was adequate MI for enhanced oil recovery opportunities at the field.

At a Jan. 7 public hearing on the issue, Bruce Laughlin, BP's Alaska North Slope reservoir management team leader, said in response to a question from commission Chair Cathy Foerster that if BP had more MI there would be opportunities to use it. But, he said, to generate more MI without the loss of natural gas liquids, NGLs, currently sold and shipped with the oil, would require installation of an additional low temperature separator, which he said would be "a very expensive project" and so far it hasn't been economic. Laughlin said BP can't justify sacrificing available NGLs to manufacture more MI and while that could change due to new technology or additional opportunities that become available in the future, it wasn't currently economic.

The 600 million cubic feet plan

Foerster asked about a requirement of CO 360 that the Prudhoe Bay operators — at that time BP and ARCO each operated half of the field — report to the commission by Dec. 15, 1995, on plans to provide an annual average volume of 600 million cubic feet per day of MI by the start of 1999.

The order required that if that volume of MI was not available, the operator should present information "to show whether operation of the pool with a lesser availability of MI would be in accordance with good oil field engineering practices and otherwise avoids waste or whether" and if the given implementation date was not practical, what date would be, she said.

Foerster said the commission has checked its files and can't find the report.

Jeff Leppo, an attorney representing BP at the hearing, told the commission it would take BP some time to respond to the question about the report. He said the company thinks it might have as many as a thousand boxes of materials related to the MI-NGL issues.

More patterns

On the issue of volumes of MI and area of coverage, Laughlin said the 1994 field development plan for Prudhoe anticipated that 4 trillion cubic feet of gas would be injected by the end of the Prudhoe Bay miscible gas project in some 200 patterns in the reservoir and the recovery of some 400 million barrels of oil. To date, he told the commission, roughly 3 tcf of gas has been injected not only into Prudhoe miscible gas projects but into all of the surrounding Prudhoe oil field pool. The target, he said, is injection of some 3.9 tcf of MI, touching 320 patterns and recovering more than 450 million barrels.

Foerster asked if there would have been greater recovery had the 600 million cubic feet per day of MI been achieved.

Referring to the CO 360 testimony, Laughlin said the goal then was 420 million to 450 million barrels of recovery and 200 patterns targeted for enhanced oil recovery, while to date 271 patterns have received MI and recovery is projected at more than 450 million barrels.

Forster also asked if BP has revisited the issue of maximizing NGLs vs. maximizing MI and Laughlin said BP looked at it on a regular basis, prompting Foerster to ask for specifics on when those kinds of studies had been done and what the studies indicated. ●

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ENVIRONMENT & SAFETY

Truck driver dies in wreck near Homer

A sad fact is that driving, of all things, is one of the top hazards in oil and gas work.

That proved true again the morning of Jan. 22, when a truck laden with drilling mud overturned near Homer, on Alaska's Kenai Peninsula, killing the driver.

The Alaska State Troopers identified the driver as Trevor Cunningham, 29, of Soldotna.

The single-vehicle wreck happened near mile 9.5 of East End Road, troopers said.

The truck was headed to Homer and overturned, separating the tank from the frame. The driver was ejected.

Cunningham was taken to the hospital in Homer where he was declared deceased, troopers said.

Some of drilling mud spilled as a result of the accident. Responders deployed boom as a precaution.

Buccaneer Energy just started drilling a well at its West Eagle prospect off East End Road, 20 miles east of Homer, and the truck belonged to a Buccaneer contractor, the Homer News reported.

—WESLEY LOY

EXPLORATION & PRODUCTION

CIE to use old Kustatan well for disposal

Cook Inlet Energy LLC is looking to get a new trick out of an old dog.

The Anchorage-based company has applied to the state Department of Natural Resources, Division of Mining, Land and Water, for a wellbore easement to use a former natural gas well as a waste disposal well.

The well is known as the Kustatan Field No. 1, located on a pad at the Kustatan production facility on the inlet's west side. The facility processes output from the company's Osprey offshore oil and gas field.

The Kustatan Field No. 1 originally was drilled as an exploration well in the 1960s, and was plugged and abandoned in 1968, Cook Inlet Energy said.

"It has been re-entered several times since then," the company told DNR.

Cook Inlet Energy, which acquired the Kustatan property in late 2009, produced gas from the well before shutting it off in November 2012.

Now the company wants to use it as a Class II disposal well. This means the well would be used to shoot drilling wastes such as cuttings, mud and produced water into a geologic formation deep underground. This is a technique commonly used in Alaska's oil fields to dispose of drilling wastes.

Cook Inlet Energy said disposal would involve no more than 5,000 barrels per day of drilling wastes.

Company executives have talked of waste disposal for westside operators as a potentially good line of business for Cook Inlet Energy.

Without oil or gas production, the authorization for using the well can no longer be administered by DNR's Division of Oil and Gas. Thus, Cook Inlet Energy needs authorization from the Division of Mining, Land and Water for the continued subsurface use of the well, DNR said in a summary of the company's easement application.

The division will grant the easement provided the Alaska Oil and Gas Conservation Commission approves disposal operations, the summary said. AOGCC regulates downhole operations.

—WESLEY LOY

EXPLORATION & PRODUCTION

Coastal areas fully open for tundra travel

The eastern and western coastal areas of state land on Alaska's North Slope are now fully open for off-road winter tundra travel, the Alaska Department of Natural Resources announced on Jan. 16. The agency had previously opened these areas, but with restrictions at a couple of locations where the dense snow pack had insulated the soil from becoming sufficiently frozen.

Off-road travel using vehicles not designed for tundra use requires specified minimum snow depths and soil temperatures, to ensure the avoidance of damage to the tundra.

To the south of the coastal areas DNR has now conditionally opened the lower foothills area. Although soil temperatures and snow cover within a portion of this area have now met the requirements for off-road winter travel, vehicles approved for tundra operations in the summer may be required in places such as wind-swept hills and exposed ridges where the snow cover is relatively thin. Snow depths are high through most of the area, DNR says.

The agency recommends that operators interested in off-road operations or winter road construction on state land contact DNR for guidance and information on up-to-date conditions. The upper foothills area remains closed, with variable soil temperatures and snow depths.

—ALAN BAILEY

FACILITIES

DNR seeks adviser on Arctic port site

The Alaska Department of Natural Resources is looking to hire a consultant for a possible industrial port development northwest of Nome.

The consultant would "advise and assist" the DNR commissioner's office on areas such as land ownership issues, legal and environmental challenges, and infrastructure and development needs, the department said in a Jan. 15 solicitation.

The prospective harbor location is known as Port Clarence.

The U.S. Army Corps of Engineers has identified Nome and Port Clarence as top candidates for a deepwater port to support industry expansion in the thawing Arctic Ocean. No such port currently exists around Alaska's northern coast.

Many experts predict rising Arctic activity including oil and gas exploration, shipping and tourism. Because of this activity, the U.S. Coast Guard is looking to establish a stronger presence in the Arctic.

Port Clarence is a federal work site, located on a long spit, established to oper-

see **PORT ADVISER** *page 15*

continued from page 1

LNG RIVALRY

In all, the approvals and applications, which still need final ratification from the Canadian government and corporate sanctioning before they become reality, are close to a staggering 21 bcf per day — 7 bcf per day more than Canada's current output, almost 10 bcf per day more than the NEB's forecast for domestic and export consumption in 2015 and 4 bcf per day more than Canada's peak consumption year in 2007.

However, the LNG applicants, a leading consultant and the British Columbia government are remaining calm in the face of those statistics.

Not even the prospect that Canadian gas could underpin two U.S. LNG operations which would then compete with Canadian proposals for a share of the Pacific-Asia market is causing any anxiety.

The British Columbia government does not believe the two Oregon proposals will affect any of the current LNG projects under way in the province, said a spokeswoman for Natural Gas Development Minister Rich Coleman.

She said British Columbia's total natural gas potential has been estimated at 2,933 tcf, enough to "support development and LNG export operations for more than 150 years."

She also said that in approving export applications Canada's National Energy Board "ensures the quantity of gas does not exceed the amount required to meet domestic demand."

Oregon LNG CEO Peter Hansen said his project will target "economically stranded" Canadian gas.

"We're not feeling any pushback from (Canadian regulators or industry) in that regard," he said.

Geoff Morrison, British Columbia manager with the Canadian Association of Petroleum Producers, said that from the gas producers' point of view selling gas into new markets is "good" and is a key objective for CAPP member companies at a time when gas sales are at a low ebb.

"We're in a competitive world and Canada is competing against the U.S. on the supply and export side," he said.

In a submission to the NEB in support of the Jordan Cove application, the firm of Navigant Consulting said domestic supplies in the U.S. and Canada are "abundant to such a degree" that they will support domestic and export demands, without allowing for the potential of resources in Alaska and Arctic Canada.

"Overall natural gas supply growth in North America continues to be remarkable ... (and) the supply-demand dynamic has the potential to be easily balanced for the foreseeable future, even as natural gas demand grows," Navigant said.

Canada's Natural Resources Minister Joe Oliver has given an assurance that the federal government will carefully assess the methods used by the NEB to determine whether the LNG requirements are surplus to Canada's forecast supplies over the license periods, which mostly cover 25 years.

—GARY PARK

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continued from page 3

BALASH Q&A

here through the Heads Of Agreement with a transparent description of the party's intent and asking for the authority to paper these broad terms and principles. So we have in the HOA landed on what can best be described as a term sheet. We are taking that term sheet to the Legislature and asking for permission to paper it. If the Legislature gives us the permission, we will paper it, complete our due diligence during pre-FEED and then come back with more definitive agreements to be considered.

Going back in time to that 2005-2006 period — and frankly, you can rewind the clock a little bit further than that. In that effort, the authorization to negotiate was provided by the Legislature in the form of the Stranded Gas Act. The Murkowski administration then conducted negotiations behind the confidentiality provisions of that law, but the agreement they emerged with went beyond those guidelines, went beyond those parameters. That's why they had to ask for amendments to the underlying Stranded Gas Development Act in order to facilitate the agreement they had struck.

In addition, that particular process had the effect of putting all of the state's chips in on a single hand, and locked in not only a number of things about gas but also things about oil — right then and there in one vote.

That is not anything at all like what we are trying to do here. In this process, we are asking the legislature to set the take terms, but we are not asking them to lock anything in — and we won't — until the producers are prepared, the other sponsor parties are prepared, to make additional commitments.

I have a little bit of perspective here as I was the staff to the Budget & Audit Committee. I managed their work. I remember clearly in May and June of 2006 people talking about this provision and that provision in the overall deal. We assembled the contractors — our experts — together one night and basically their takeaway was you can quibble over some of those details, but where the SGDA deal falls short is the state is not getting anything. There was no real commitment. It was incredibly unbalanced in favor of the other parties and I think that's due at least in part in the manner in which it was negotiated. Then Gov. Murkowski kept promising 'we are going to have a deal, we are going to have a deal.' In some ways that exposed him as a negotiator. He was the one setting the expectation. I think some of the other parties were able to use that to their commercial advantage at the table.

In this case, Gov. Parnell has been loath to set expectations because he didn't want to provide that same commercial advantage to the counter parties. He also has made it very clear to the companies at the highest levels that this is going to require a balanced approach with commensurate commitments on either side. We are prepared to take some steps and they need take some steps, and we are going to repeat that process until all of the parties are fully committed to the project. We are not going to put all of our chips in one hand.

Petroleum News: So the state has an equity in almost every stage?

Balash: That's right. Even the agreement with TransCanada is rooted in the state's ownership position. We've set out an initial contract term, and that has a depreciation schedule that goes along with it. TransCanada is looking at realizing all the depreciation during that initial term, but at the end of that term the state has the option to call back its equity interest from TransCanada and buy them out at the netbook value. If they fully depreciated their interest in the project, that netbook value is going to be really, really low. We never lose sight of that equity perspective. As an owner state, it's important that we act like an owner state and I think we are doing that here.

Petroleum News: So do you have a sense of the breakdown of the equity of the project?

Balash: I've got a lot of ways to look at it and break it down. The HOA contemplates the state coming in somewhere between 20 and 25 percent. If the state is 20 then the residual positions are: Exxon is at 34.6; BP is at 22.5; Conoco is at 22.9. If the state is at 25 percent, Exxon is at 32.5; BP at 21.1 and Conoco at 21.4.

Petroleum News: So would this make Exxon the operator the way BP is the operator of TAPS?

Balash: That is something that would need to formally be voted on in the equity structures and agreements. Very clearly Exxon is the lead party in the development phase right now. There likely would be different operators in phases of the project. You see that reflected in the project team chart where the team lead is ExxonMobil, the integration lead is ExxonMobil, but the liquefaction plant is Conoco, the pipelines is TransCanada, and for the producing fields — upstream — that's BP. That's an important point I want to build on. Overall, size matters, right, your position in the equity structure matters. One of the reasons that Commissioner Rodell and I decided to put all of our gas into TransCanada capacity in the GTP and pipeline is to make sure their block overall was big enough to command a lead role so that should give them an edge in getting to be the operator of the pipeline long-term, certainly into the execution of construction.

Petroleum News: One of the criticisms of SGA and, conversely, one of the praises of AGIA is that it would encourage competition and new entrants into exploration and field development. Does this path keep that in mind?

Balash: Absolutely. Those features in AGIA embodied in some of the must-haves really were about furthering key state interests. One of those was low tariffs. Another is an expansion policy. In the Heads Of Agreement, we have landed on key terms and principles to advance both of those. The first is low tariffs. The way AGIA sought to advance a low tariff was by requiring a minimal threshold for debt in the capital structure (70 percent financing; 30 percent cash). Part of the reason for that is historically the state has been interested in low tariffs and the producers not so much. That's not what drives their decision making because they are paying themselves. So we had a misalignment of interests between ourselves and the producers where the tariff ends up. For the state it's low, low, low. That's the answer every time for a variety of reasons. It results in a greater royalty value, a greater tax value and it makes our property between Prudhoe Bay and Point Thomson more valuable. In this overall commercial structure identified in the HOA the state will be in position to establish the financing of its infrastructure and the producers will be free to pursue whatever financing they require. That has proven to be a powerful path because each party is free to pursue its own ends.

For us, it's embodied in the terms we struck with TransCanada. We are not pursuing equity just so we can be in the pipeline business. What we are after is establishing terms of service that achieve state interests — key state interests. In this case, low tariffs. We got with TransCanada a 75-25 debt equity structure, which is huge. It allows us to get an independent pipeline company operating a significant portion of the pipeline, and they will be free, as one of the parties, to expand the components of the project when they have additional customers. The expansion principles in the Heads Of Agreement really are one of most important pieces that we've landed in all of this. What the principles say — and it's in the appendix, appendix A — is that any party can expand any component of the project so long as they are prepared to do so at their sole risk. What that means is the other parties won't be affected. For instance if there is additional demand for capacity that's in-state, TransCanada will be free to expand to meet that demand. The other parties can participate in the expansion, but they are under no obligation to do so. A lot of that stuff as far as the pipeline and GTP, we've been around the horn with companies over the years. And we had a pretty good handle on how this would work. What's really different about LNG projects is the regulation of liquefaction.

Liquefaction terminals and liquefaction trains are regulated solely by the Federal Energy Regulatory Commission under Section 3 of the Natural Gas Act. That regulation is largely for environmental health and safety. They don't regulate for access and they don't regulate for rates. No matter how good the terms were for access and expansion on the pipeline and GTP, it wasn't going to mean anything if we didn't do something about the liquefaction.

So in these expansion principles in Appendix A, we've landed on a process for expansions to take place on any component except for the liquefaction trains. However, any party can add a liquefaction train. As best as we can tell, that's a pretty unique feature. Ordinarily you would see some other mechanism, even if it were a majority vote among the parties, to add a train. In this case a single party can add a train, but they have to be willing to pay for it. That's a really big deal and something we think was and is critical to the state's long-term future. We will be able to show in a couple of weeks, as we get through the legislative presentations, what that means potentially for the state. ●

EDITOR'S NOTE: Part 2 of this Q&A will appear in the Feb. 2 issue.

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continued from page 13

PORT ADVISER

ate Coast Guard Loran equipment.

"The natural protection offered within Port Clarence and its proximity to Bering Strait has led to the use of this natural harbor since whaling vessels were active in the region in the 1860s," the Army Corps wrote in a 2013 Arctic port study. "It is currently used by barge operators as they await ice retreat north of Bering Strait each summer."

The DNR said the consultant will "research and review existing information about Port Clarence and its land characteristics to provide experienced insight to the commissioner's office about the natural advantages and challenges of the site for infrastructure development."

The cost of the consultant's work "should not exceed $100,000," DNR said.

The agency set a deadline of Jan. 21 for proposals.

—WESLEY LOY

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Petroleum news

Oil Patch Bits

Soper named Five Star December employee of the month

COURTESY FIVE STAR

Julie Soper received Five Star recognition for the month of December for being an outstanding employee. Soper is a huge asset to Five Star Oilfield, her hard work and dedication is noticed by all. She is constantly going above and beyond to make sure the client is completely taken care of and also that her coworkers have what they need to do their jobs to the fullest, making the workplace a fun place to be with her positive attitude.

Employees of the month are based on client feedback and site visits performed by the operations manager of Five Star Oilfield Services.

Five Star Oilfield Services specializes in providing remote sites with catering and cleaning services, solving the most challenging problems companies face when operating in remote parts of the world and in areas that lack sufficient accommodations.

Tabitha Trosper joins Golder Associates group

Golder Associates Inc. Anchorage office welcomes new hire Tabitha Trosper.

Trosper is an engineering geologist with Golder Associates Inc. Prior to joining Golder; she served as geologist in the engineering geology group of an environmental and engineering consulting firm where she evaluated geologic hazards, provided field support for engineering geology and geotechnical projects throughout Washington and other regions of the United States. Trosper has just embarked on her career in consulting with over two years of engineering geology and geotechnical field exploration experience. She is a graduate of Central Washington University, Ellensburg, with a Bachelor of Science and master's degree in geology. While at CWU, Trosper's focus was on geomorphology, several of her research projects described the paleoenvironments of archaeological sites in the Northwestern United States and Central Mexico. She is also passionate about science education and has participated in many educational outreach programs, providing supplemental scientific instruction and promoting careers in science.

Usibelli Coal Mine completes 2013 accident free

Usibelli Coal Mine Inc., based in Healy, Alaska, said it has achieved a one calendar year

see **OIL PATCH BITS** *page 18*

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

continued from page 1

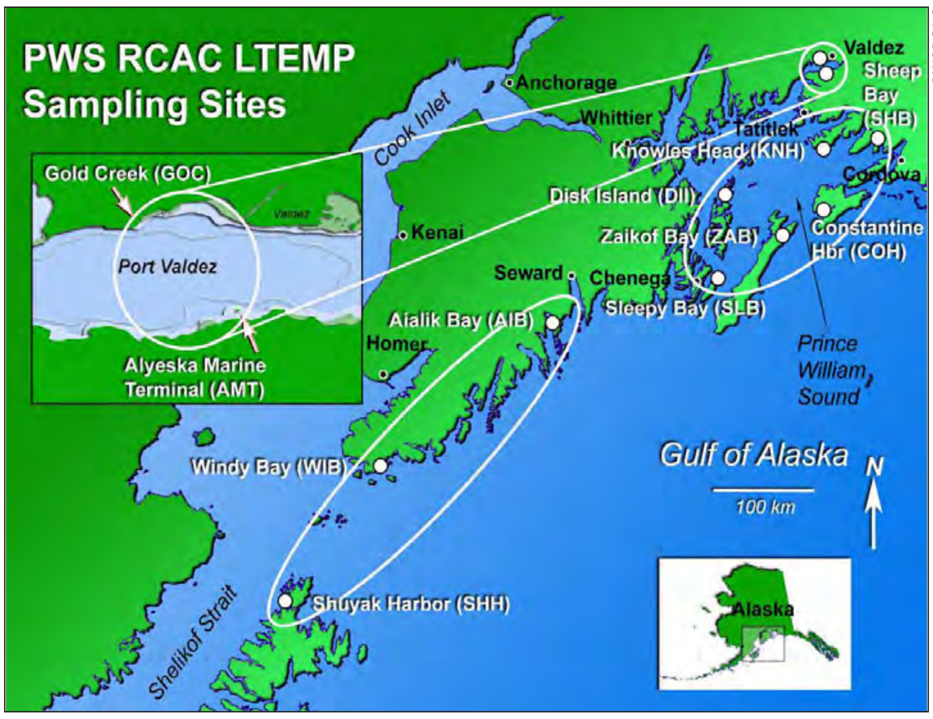
LTEMP

likely reflects a number of factors, the report says.

First, North Slope oil production has been declining for years. Under 600,000 barrels of crude per day now flows down the 800-mile trans-Alaska pipeline, which ends at Valdez. Throughput peaked at more than 2 million barrels per day in 1988. The decline means less tanker traffic.

Second, the tanker fleet calling at Valdez has converted from single-hull to double-hull ships. These new ships have segregated tanks to hold ballast water, meaning they carry their ballast in clean tanks, not in the same tanks used to carry crude oil. The result is less oily ballast water must be cycled through the treatment plant at the Valdez terminal, with treated wastewater dumped into Port Valdez.

Third, the ballast water treatment facility has become more efficient at removing pollutants known as polycyclic aromatic hydrocarbons, or PAHs, the monitoring report says.



PWSRCAC

Results from monitoring sites in Prince William Sound and the Gulf of Alaska "demonstrate that the region is exceptionally clean," the report says.

The council's role

An Anchorage-based company, the Alyeska Pipeline Service Co., operates the Valdez terminal. The major owners in Alyeska are BP, ExxonMobil and ConocoPhillips.

Payne Environmental Consulting Inc. produced the LTEMP report for the Prince William Sound Regional Citizens' Advisory Council, a Valdez-based congressionally sanctioned organization that monitors the terminal and associated tanker activity.

The council was to review the report at its Jan. 23-24 board meeting in Anchorage.

An RCAC memo explains that the Oil Pollution Act of 1990, which Congress passed in the wake of the Exxon Valdez oil spill, directs the council to "devise and manage a comprehensive program of monitoring the environmental impacts of the operations of terminal facilities and crude oil tankers while operating in Prince William Sound."

LTEMP is the project designed to address this directive, the memo says.

Among other findings in the report:

In sediments at berth 4, one of the two active tanker loading berths at the Valdez Marine Terminal, average total PAH levels are "very low."

At the Gold Creek monitoring site, across Port Valdez from the tanker terminal, sediments recently have shown "extremely low" total PAH concentrations.

Beyond Port Valdez, there has been a continuing regional decline in total PAH concentrations in Knowles Head mussels. Knowles Head is a safe anchorage well inside Prince William Sound where oil tankers sometimes pause.

The monitoring study does not signify that the crude oil spilled from the Exxon Valdez has vanished.

The council says staff in August took a field trip to Northwest Bay on Eleanor Island, a bay heavily oiled in 1989 and subsequently remediated.

"A few hastily dug shallow pits dug (6 inches to 1 foot deep) in a rocky beach's tidal zone all indicated the continued presence of Exxon Valdez oil," the council said a status report on its various projects. "Oil density on the surface went well beyond mere sheen." ●

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continued from page 16

OIL PATCH BITS

safety record for 2013, with more than 120 employees at UCM achieving in excess of 530 continuous days without a lost time accident.

"This is a significant accomplishment considering the challenging conditions in which we work every day. Operating and maintaining heavy equipment and conducting mining operations — essentially 24 hours a day, 7 days a week, all year long, in rain, snow, extreme wind conditions, in the dark of winter, and in many cases very remote locations on the mine property are not easy tasks," said Alan Renshaw, UCM general manager.

"I am very proud of our people. We have a professional and dedicated workforce with great teamwork and leadership. The safety of our employees is priority number one. It takes the constant vigilance of every employee every day, all day long. Our goal is to provide a quality product, in the requested quantities, and with on-time deliveries; all accomplished in a safe manner. My compliments go out to every member of the company; I am extremely proud of everyone," added Joe Usibelli Jr., president of Usibelli Coal Mine.

Usibelli Coal Mine is a fourth generation, family-owned, all-Alaskan business and the only operational coal mine in Alaska.

Editor's note: All of these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in March.

continued from page 1

STATE OF THE STATE

project and how it could be competitive.

"Alaska can best control her own destiny if we own a stake or participate in the Alaska LNG Project," Parnell said, telling legislators that an equity interest allows the state to share "in the profits of the project, rather than handing them all to someone else."

It also means the state "will better understand and can more effectively negotiate and ensure the lowest possible cost."

The governor said the legislative approval process he will propose will be phased, and "will be more open and transparent to the public than either the Stranded Gas Act or the Alaska Gasline Inducement Act," the most recent laws under which the state attempted to negotiate a North Slope natural gas project.

When those acts were passed, "everyone assumed that in order to get a gas line, we had to negotiate all the fiscal terms at the outset," Parnell said, and the impact of that belief was that "the state carried all the risk upfront for decisions worth billions of dollars without having the benefit of information, time and analysis to get it right."

The governor said his approach would require the parties to "make commensurate proportionate commitments to go forward in phases," and at each phase, the administration would seek "review and approval" of key decisions from legislators.

Approval sought in this session, the governor said, would involve approval of the guidance document negotiated by the administration team (the Heads Of Agreement which the governor announced Jan. 10), and legislation allowing the state to be part of the pre-front end engineering and design phase of the project. The total pre-FEED cost will be about half a billion dollars, Parnell said, with the state's portion between $70 million and $90 million.

Meanwhile, AGDC, the Alaska Gasline Development Corp., is the state's backup position, the governor said, and "on track for an open season in early 2015."

If the Alaska LNG Project falters, "we can still get gas to Alaskans first with AGDC's smaller volume project," he said.

"The gas line legislation I ask you to consider is important," Parnell told legislators. "It's important to create a competitive investment environment for any project that gets Alaska's gas to Alaskan homes and businesses. The legislation is important to both AGDC's smaller volume gas line project and the larger Alaska LNG Project," he said.

Democrats have concerns

On the gas line issue, the Legislature's leading Democrats highlighted concerns they have about the governor's gas line proposal.

Rep. Chris Tuck, D-Anchorage, the new House minority leader, said Democrats "want to partner with the oil industry and others who want to help develop our resources, but we will not take the backseat in those negotiations."

Tuck said Democrats "have long held that owning a piece of the pipe can be a great way to bring the full benefits" of a gas project to Alaskans, but cited the deal negotiated by the administration of former Gov. Frank Murkowski as an example that "the devil is in the details."

He said it was important to make sure a deal "is a good deal for Alaskans."

"We want a gas line, but we cannot afford to give away our gas like the governor did our oil," Tuck said, referring to passage of last year's oil production reform, Senate Bill 21, which Democrats opposed.

Sen. Hollis French, D-Anchorage, the new Senate minority leader, said Democrats' "approach to the gas line is extremely simple: gas line yes; giveaway no."

He said to ensure that a gas pipeline is not a giveaway the "deal must be structured for the next 50 years," with access to gas for consumers at a reasonable price, as well as access to the pipeline for new oil and gas companies coming to Alaska.

French also tied his remarks on the gas line proposal into last year's passage of SB 21. He said Alaskans should view the governor's gas line approach "with some skepticism," since it was the Parnell administration "that pushed last year's oil tax giveaway." ●

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continued from page 1

BP OUTLOOK

Even with that slim growth, oil production in 2035 would be 19 million barrels per day higher than 2012. BP expects more than half of the additional supplies to come from non-OPEC countries, particularly from tight oil from the United States and oil sands from Canada.

The forecast predicts that the United States will overtake Saudi Arabia as the leading liquids producer this year and expects oil imports to fall nearly 75 percent between 2012 and 2035 as the country becomes increasingly self-sufficient. The rapid growth in North American oil supplies would likely force OPEC to cut back production, according to BP Chief Economist Christof Ruhl, creating spare capacity at levels not seen since the 1980s.

In such a situation, Middle Eastern exports to the West would likely go to Asia instead.

"Trade becomes heavily concentrated," Ruhl said.

This growing self-sufficiency in the United States oil markets has led policymakers such as Sen. Lisa Murkowski to call on the federal government to lift its ban on oil exports.

The situation is even knottier for natural gas.

The forecast expects gas to be the fastest growing fuel, with demand growing at 1.9 percent per year to reach 497 billion cubic feet per day by 2035, according to the forecast.

Shale gas will handle some 46 percent of the growth in demand, according to the forecast, but the global impact of shale gas should remain limited, accounting for just 21 percent of global production and 68 percent of domestic production by 2035. That's because even with all the talk of shale, the forecast expects conventional gas production from developing countries to grow faster than global production of unconventional gas.

The boom in shale gas in the United States is currently "under laboratory conditions," according to Ruhl. The large increase in production combined with limited exports is allowing forecasters to study how shale gas production changes energy markets within a country. "What we are seeing is that natural gas first penetrates the power sector, then penetrates industry, and then transport. So there's a sequence of it. And on top of that penetration, in all areas of application, we see exports of course increasing," Ruhl said.

According to the forecast, this trend will make the U.S. the second largest gas exporter by 2035, when a proposed Alaska liquefied natural gas project would be well into operation.

The forecast expects North America to account for 71 percent of global shale gas production by 2035, but it also expects North American production to slow after 2020 and it expects China to gradually edge into the market toward the end of the forecast.

—ERIC LIDJI

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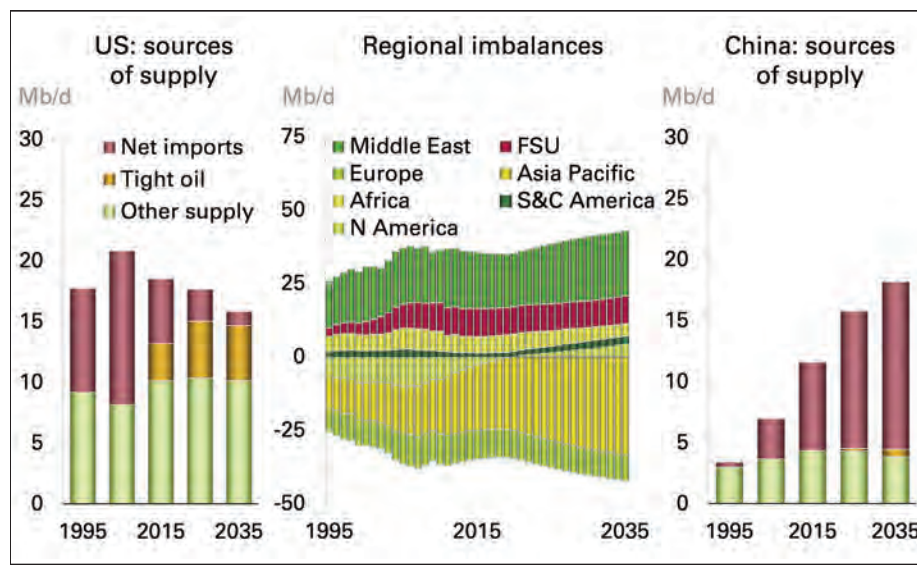

COURTESY BP

continued from page 1

LEASE SALE APPEAL

nies bought leases in the sale and Interior received $2.6 billion in bonus bids. Shell has started exploration drilling in its leases and hopes to continue with that drilling, perhaps as soon as the summer of 2014.

A finding that the lease sale was invalid presumably raises question marks over the legal status of the leases.

Shell has issued a statement saying that it is "reviewing the situation," while BOEM has declined to comment while the matter is subject to litigation.

In a Jan. 22 statement, environmental activist organization Greenpeace characterized the court's decision as a "victory for the Arctic."

"We applaud the hard work and dedication of the many groups who have pushed this case through the courts, and congratulate them on today's vindication," said Greenpeace Arctic Campaign Leader Gustavo Ampugnani. "This decision should give President Obama pause to reconsider the dangerous path he's heading down by opening up the precious Arctic to rapacious oil giants."

Sen. Mark Begich expressed optimism about continued Chukchi Sea exploration.

"The Arctic has already been and will continue to be subjected to unprecedented safety standards and today's announcement does not delay the important progress we have made," Begich said. "Alaskans know how to develop our resources and that is why I continue to be optimistic that we will see safe, responsible development in the Arctic this summer."

Began in 2008

The Native Village of Point Hope, the Inupiat Community of the Arctic Slope and 12 environmental organizations launched the appeal against the EIS in the federal District Court for Alaska in 2008.

The 9th Circuit has accepted Beistline's decision that the questions relating to missing environmental data have been resolved. However, the two judges that formulated the majority opinion homed in on a different question, the question of whether Interior had adequately considered how much oil might economically be produced from Chukchi Sea oil fields.

In July 2010 District Court Judge Ralph Beistline issued an order upholding claims that, in preparing the EIS, Interior had failed to adequately consider the environmental impacts of potential natural gas development in the Chukchi and had not adequately considered the significance of missing Chukchi Sea environmental information.

Interior proceeded to make major revisions to the EIS and published a new version of the document in October 2011. And in February 2012 Beistline formally dismissed the appeal, saying that the deficiencies in the EIS had been corrected.

Shell subsequently proceeded to start its Chukchi Sea drilling program in the summer of 2012.

Meantime, in April 2012 the appellees elevated the appeal case to the 9th Circuit.

Oil volume estimate

The 9th Circuit has accepted Beistline's decision that the questions relating to missing environmental data have been resolved. However, the two judges that formulated the majority opinion homed in on a different question, the question of whether Interior had adequately considered how much oil might economically be produced from Chukchi Sea oil fields. This estimated oil volume would presumably impact estimates of how much development activity might take place and hence how much environmental impact the development might have. The oil volume estimate may also impact assessments of oil spill risks.

Using as evidence a series of internal BOEM emails, in which BOEM staff discussed the oil volume estimate to use in the EIS, the two 9th Circuit judges who formulated the majority decision concluded that BOEM had not adequately evaluated the oil volume figure, with the 1 billion barrel assumption being an arbitrary number.

More fields?

This figure apparently represented the possible production from an initial Chukchi Sea development, based on assumptions that a field smaller than this would not be viable and that the probability of finding a field larger than this would be relatively low. But the EIS does not explain why production would be expected to stop with that first field, nor does it take into account variations in oil prices that might impact production economics, the judges wrote.

"Previous evaluations of the Chukchi Sea oil development had assumed that multiple oil fields would develop once commercial development was viable," the judges wrote. "On the record before us, it remains unclear why BOEM chose to analyze the lowest amount of oil that could be produced in the Chukchi Sea from the smallest number of oil fields that could be developed." ●

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