Petroleum news

**page 4** Doogan says let ACES ride; cites past changes, revenue cut concerns

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## Special report inside this issue

Alaska Shale

SPECIAL REPORT

Petroleum news

Steeply dipping panel of Cretaceous pebble shale unit, GRZ, and Hue Shale at Hue Creek in ANWR. Rusty brown and orange weathering is characteristic of tuffaceous intervals in this succession. Stratigraphic younging direction is to the right. View to west.

P.L. DECKER, 2005

Our Vision
Potential Oil Production Profile

● EXPLORATION & PRODUCTION

**Why Alaska sees hope in source rocks**

*State petroleum geologist tells lawmakers that North Slope source rocks resemble some of the hottest shale plays in North America*

By ERIC LIDJI
For Petroleum News

The State of Alaska is "cautiously optimistic" about oil development from source rocks.

"Optimistic" because the geology of the Alaska North Slope resembles the hot Eagle Ford shale formation in South Texas, and Great Bear Petroleum's leases are "well positioned" to develop that geology, a Division of Oil and Gas petroleum geologist recently told state lawmakers. "Cautiously" because developing source rocks is an entirely new concept in Alaska that will require a lot of equipment, crews and water, and some trial and error.

"If these production pilots and exploration success do occur then full-scale development, if it were to occur, could be quite a whirlwind," Paul Decker said on Feb. 23. "But, you know, things remain to be seen. But at this point I think we're cautiously optimistic."

The play Great Bear is proposing to develop at its new 537,500-acre North Slope lease position is so new for Alaska that it doesn't even have an agreed upon name, but Decker is calling it "source-reservoired oil," meaning that the source rock is also the reservoir, because the rocks are so tight that they hold onto the oil they generate like a traditional geologic trap.

**What makes for good rocks?**

The North Slope is home to three "prolific" source rock intervals that are candidates for development: the Shublik, the Kingak and the GRZ/Hue shale system, from deepest to shallowest. These source rocks exist some 8,000 to 13,000 feet underground.

The factors that make source rocks good candidates for development include the organic chemistry — the ingredients for making oil, elements like carbon and hydrogen — and the thermal maturity — the underground heat needed to turn those elements into oil.

For source rocks to become the "kitchen" where oil and gas gets "cooked," they must be deep enough for the heat of the earth to reach the proper temperatures. Shallow rocks are too cool, or "immature," and won't generate oil and gas for ages, but in the hotter depths below those immature rocks are usually an "oil window" and a deeper "gas window."

The tectonic history is also important, because natural fracturing can make recovery easier and needs to be well understood in order to design, drill, and complete the

see SOURCE ROCKS page 19

● LAND & LEASING

**Duncan: Our timing was fortuitous**

*Great Bear carefully selected shale oil acreage won in 2010 North Slope areawide lease sale; prize was three of richest source rocks in world*

By KAY CASHMAN
Petroleum News

According to Great Bear Petroleum's top executive, Alaska has three of the most prolific, world class, source rocks in the world. Individually, Ed Duncan says, "as source rocks, they are superior to the Eagle Ford shale play in Texas, currently considered the hottest conventional oil play in the world."

As for Eagle Ford being the hottest shale oil play, he says, "We believe that is about to change."

Great Bear entered Alaska in October by placing winning bids on more than 500,000 acres in the State of Alaska's annual North Slope lease sale,

see GREAT BEAR TIMING page 18

## Fiscal framework negotiations next for Mackenzie Gas Project

Having emerged intact from a drawn-out, tangled regulatory process, the Mackenzie Gas Project now faces a fresh round of challenges, building toward a final corporate decision on whether to start construction.

The venture is now largely in the hands of its proponents, who now have to weigh the future of North American gas demand and price outlook as they try to decide whether it can be economically viable in the 2018-20 startup period and for at least the next 30 years.

The National Energy Board, following approval from the federal government cabinet, issued a certificate of public convenience and necessity March 9.

see **MAC GAS** page 28

## BP starting heavy oil facility to test production feasibility

It has been nearly a year since BP completed construction of its $100 million heavy oil test facility on Alaska's North Slope, but the company has finally completed commissioning of the facility and is about to start operations at the plant, Eric West, manager of BP's Alaska renewal team, told a group of state legislators at a "lunch and learn" session in Juneau on March 10.

"It's essentially ready to go," West said.

The facility, on S-pad, the most southerly well pad in the BP-operated Milne Point field, will try extracting heavy oil from the relatively shallow Ugnu formation using a technique called cold heavy oil production with sand, or CHOPS. In this system, a device called a progressive cavity pump, a kind of Archimedes screw that spins at high speed

see **HEAVY OIL** page 26

● EXPLORATION & PRODUCTION

# Spartan 151 loaded

*Escopeta's jack-up rig on heavy lift vessel, scheduled to sail March 18*

By ERIC LIDJI
*For Petroleum News*

Escopeta Oil has loaded the Spartan 151 jack-up rig onto a heavy lift vessel at a dock in Freeport, Texas. The vessel is scheduled to set sail on Friday, March 18, Escopeta President Danny Davis told Petroleum News March 17 as this edition went to press.

It will be the first time in more than a decade that a jack-up rig is headed to Alaska. But Escopeta must overcome a few more hurdles before it can begin its exploration campaign in upper Cook Inlet.

The ship will sail around the tip of South America on its way to Cook Inlet. Once the jack-up is unloaded, it must be outfitted with additional equipment before it can begin drilling.

*The ship must sail around the tip of South America on its way to Cook Inlet.*

On March 9, two officials from the Alaska Oil and Gas Conservation Commission flew to Texas to inspect the Spartan 151 but, as expected, said they needed to inspect it again after it arrives in Alaska and blowout prevention equipment is installed and tested.

In February, Davis announced Escopeta was purchasing a 15,000-pound blowout preventer to use on the Spartan 151, a major step-up in the equipment previously used on the rig in the Gulf of

see **JACK-UP RIG** page 23

● EXPLORATION & PRODUCTION

# BRPC spuds North Tarn

*Joint venture begins work on the only North Slope exploration well for 2010-11*

By ERIC LIDJI
*For Petroleum News*

Brooks Range Petroleum Corp. spud its North Tarn No. 1 exploration well in the central North Slope of Alaska on March 13, the local independent said.

North Tarn No. 1 is on state land east of the Miluveach River, about two miles west of the Kuparuk River unit. BRPC spud the well using Nabors rig 9ES and accessed the well site using a winter ice road and pad system built by Peak Oilfield Services.

BRPC plans to drill the well to a total measured depth of 6,440 feet to target both the Brookian formation and the deeper Kuparuk formation. The Brookian is the same formation producing at Tarn, the Kuparuk River unit satellite just to the south, while the Kuparuk is the main formation producing at the prolific Kuparuk River unit to the east.

BRPC estimates that the Brookian reservoir could contain some 35 million barrels of oil and that the Kuparuk reservoir could contain an additional 6 million barrels of oil. BRPC previously told Petroleum News that it believes the smaller Kuparuk formation presents a better bet for initial development because of the complex geology of the Brookian.

BRPC hopes to complete operations at North Tarn

see **NORTH TARN** page 28

● NATURAL GAS

# Keeping all options open

*ConocoPhillips plans to preserve Cook Inlet LNG plant for possible future use*

By ALAN BAILEY
*Petroleum News*

When ConocoPhillips announced in February that it would close the LNG plant that it operates on Alaska's Kenai Peninsula, the company said that it would begin mothballing the plant after it offloads its last consignment of LNG, probably in April or May. And at an Anchorage Energy Task Force meeting on March 15 Dan Clark, manager of Cook Inlet assets for ConocoPhillips Alaska, said that the company plans to put the plant into a "preserved condition."

"Our intent is to preserve the plant so that whatever future opportunities might come up, whether it be future exports or an import situation, the plant would be in a position to be ready," Clark said. Those opportunities could include conversion of the facility for importing LNG, to bolster local utility gas produc-

see **LNG PLANT** page 27


**The Nikiski LNG plant**

# contents

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

# Alaska - Mackenzie Rig Report

| Rig Owner/Rig Type | Rig No. | Rig Location/Activity | Operator or Status |
|---|---|---|---|

## Alaska Rig Status

### North Slope - Onshore

| Rig Owner/Rig Type | Rig No. | Rig Location/Activity | Operator or Status |
|---|---|---|---|
| **Doyon Drilling** | | | |
| Dreco 1250 UE | 14 (SCR/TD) | Prudhoe Bay W-202 | BP |
| Sky Top Brewster NE-12 | 15 (SCR/TD) | Kuparuk 2L-306 | ConocoPhillips |
| Dreco 1000 UE | 16 (SCR/TD) | Milne Point MPC-22/01 | BP |
| Dreco D2000 UEBD | 19 (SCR/TD) | Alpine CD3-125 | ConocoPhillips |
| OIME 2000 | 141 (SCR/TD) | Alpine CD3-198 | ConocoPhillips |
| TSM 7000 | Arctic Wolf #2 | Going to Nisku, AB | Fex/Available |
| **Nabors Alaska Drilling** | | | |
| Trans-ocean rig | CDR-1 (CT) | Stacked, Prudhoe Bay | Available |
| AC Coil Hybrid | CDR-2 | Kuparuk 1E-08 | ConocoPhillips |
| Dreco 1000 UE | 2-ES | Prudhoe Bay Stacked out | Available |
| Mid-Continental U36A | 3-S | Prudhoe Bay Stacked out | Available |
| Oilwell 700 E | 4-ES (SCR) | Milne Point MPF-65 | BP |
| Dreco 1000 UE | 7-ES (SCR/TD) | Prudhoe Bay DS 05-07 | BP |
| Dreco 1000 UE | 9-ES (SCR/TD) | Mobilizing to North Tarn #1 | Brooks Range Petroleum |
| Oilwell 2000 Hercules | 14-E (SCR) | Prudhoe Bay Stacked out | Available |
| Oilwell 2000 Hercules | 16-E (SCR/TD) | Prudhoe Bay Stacked out | Available |
| Oilwell 2000 | 17-E (SCR/TD) | Prudhoe Bay Stacked out | Available |
| Emsco Electro-hoist -2 | 18-E (SCR) | Stacked, Deadhorse | Available |
| Emsco Electro-hoist Varco TDS3 | 22-E (SCR/TD) | Stacked, Milne Point | Available |
| Emsco Electro-hoist | 28-E (SCR) | Stacked, Deadhorse | Available |
| Emsco Electro-hoist Canrig 1050E | 27-E (SCR-TD) | Stacked at Point Thompson | Available |
| Academy AC electric Canrig | 105-E (SCR/TD) | Stacked at Deadhorse | Available |
| Academy AC electric Heli-Rig | 106-E (SCR/TD) | Stacked at Deadhorse | Available |
| OIME 2000 | 245-E | Oliktok Point OP 10-09 | ENI |
| **Nordic Calista Services** | | | |
| Superior 700 UE | 1 (SCR/CTD) | Prudhoe Bay Drill Site PT-04L1 | BP |
| Superior 700 UE | 2 (SCR/CTD) | Prudhoe Bay Drill Site S-01C | BP |
| Ideco 900 | 3 (SCR/TD) | Kuparuk Well 2V-09 | ConocoPhillips |

### North Slope - Offshore

| Rig Owner/Rig Type | Rig No. | Rig Location/Activity | Operator or Status |
|---|---|---|---|
| **BP (rig built & being assembled by Parker)** | | | |
| Top drive, supersized | Liberty rig | Endicott SDI for Liberty oil field | BP |
| **Nabors Alaska Drilling** | | | |
| OIME 1000 | 19-E (SCR) | Oooguruk ODST-46i | Pioneer Natural Resources |
| Oilwell 2000 | 33-E | Prudhoe Bay Stacked out | Available |

### Cook Inlet Basin – Onshore

| Rig Owner/Rig Type | Rig No. | Rig Location/Activity | Operator or Status |
|---|---|---|---|
| **Aurora Well Service** | | | |
| Franks 300 Srs. Explorer III | AWS 1 | Stacked out on the west side of Cook Inlet near Tyonek | Available |
| **Cook Inlet Energy** | | | |
| Atlas Copco RD20 34 | | Undergoing winterization at W. McArthur River Unit | Cook Inlet Energy |
| **Doyon Drilling** | | | |
| TSM 7000 | Arctic Fox #1 | Beluga Stacked | Available |
| **Marathon Oil Co. (Inlet Drilling Alaska labor contractor)** | | | |
| Taylor | Glacier 1 | Moving to stack out in Kenai | Available |
| **Nabors Alaska Drilling** | | | |
| Continental Emsco E3000 | 273 | Stacked, Kenai | Available |
| Franks | 26 | Stacked | Available |
| IDECO 2100 E | 429E (SCR) | Stacked, removed from Osprey platform | Available |
| Rigmaster 850 | 129 | Kenai Stacked out | Available |
| **Rowan Companies** | | | |
| AC Electric | 68AC (SCR/TD) | Demobilizing and prepping to ship to Lower 48 | Pioneer Natural Resources |
| **Kuukpik** | 5 | Mobilizing to LEA #1 for completion/testing | Linc Energy |

### Cook Inlet Basin – Offshore

| Rig Owner/Rig Type | Rig No. | Rig Location/Activity | Operator or Status |
|---|---|---|---|
| **Chevron (Nabors Alaska Drilling labor contract)** | | | |
| | 428 | M-11 Steelhead Platform | Chevron |
| **XTO Energy** | | | |
| National 1320 | A | Coil tubing cleanout planned off Platform A in the near future | XTO |
| National 110 | C (TD) | Idle | XTO |

## Mackenzie Rig Status

### Canadian Beaufort Sea

| Rig Owner/Rig Type | Rig No. | Rig Location/Activity | Operator or Status |
|---|---|---|---|
| **SDC Drilling Inc.** | | | |
| SSDC CANMAR Island Rig #2 | SDC | Set down at Roland Bay | Available |

### Central Mackenzie Valley

| Rig Owner/Rig Type | Rig No. | Rig Location/Activity | Operator or Status |
|---|---|---|---|
| **Akita/SAHTU** | | | |
| Oilwell 500 | 51 | Has left the NWT | MGM Energy Corp. |

*The Alaska - Mackenzie Rig Report as of March 17, 2011.*
*Active drilling companies only listed.*

**TD = rigs equipped with top drive units WO = workover operations**
**CT = coiled tubing operation SCR = electric rig**

*This rig report was prepared by Marti Reeve*

JUDY PATRICK

### Baker Hughes North America rotary rig counts*

| | Feb. 11 | Feb. 4 | Year Ago |
|---|---|---|---|
| US | 1,715 | 1,707 | 1,407 |
| Canada | 628 | 625 | 479 |
| Gulf | 25 | 25 | 49 |

| **Highest/Lowest** | | |
|---|---|---|
| US/Highest | 4530 | December 1981 |
| US/Lowest | 488 | April 1999 |
| Canada/Highest | 558 | January 2000 |
| Canada/Lowest | 29 | April 1992 |

*Issued by Baker Hughes since 1944

● GOVERNMENT

# Doogan wants to let ACES tax system ride

*Anchorage Democrat says credits show companies using system, believes state should hold off on changes, see what companies do next*

**By STEVE QUINN**
*For Petroleum News*

State Rep. Mike Doogan is used to being in the minority. After all, he's a Democrat in Alaska. Doogan arrived to the Capitol for his first term in 2007 armed with his signature sarcastic touch that can lighten a tense mood created by the divisive oil and gas tax debate. The man who once invoked the term "bumfuzzled" in a previous tax discussion now sits on the House Finance and Legislative Budget and Audit committees. The Finance Committee has begun reviewing Gov. Sean Parnell's tax rewrite plan, House Bill 110. Doogan sat down with Petroleum News to discuss oil and gas issues.

*Petroleum News: There are a lot of ideas floating around the building about what needs to be done with the state's tax system. What do you feel should be done?*

Doogan: To be honest with you I think it should be left alone right now. I'm not sure where the dividing lines are, but we have rewritten those taxes a lot. In my view we should wait and see what they do. We know some things that we've done are working to the extent that we will spit out nearly a billion dollars in tax rebates both for the big producers and smaller producers out there trying to find oil. We have no idea what they've done. If you decide you're going to do something because you want to have a certain affect and you don't wait to see whether it has that affect, you're just wasting your time. What we've done is making some pretty substantial changes in the new oil tax regime. And it's my view it's time to see what they do first.


REP. MIKE DOOGAN

*Petroleum News: That was the argument against breaking away from PPT, that enough time hadn't been given.*

Doogan: I wouldn't have argued with that position at that time. We had a very popular governor who wanted a change. They were capable of making rational arguments in favor of making those changes. It was a combination of policy and politics just like anything else. I decided to go along with that and I did. Now we have a governor elected for the first time and he wants a change, but he doesn't have the kinds of arguments in favor of change that she did. I haven't actually been able to sit and listen to the entire case being made yet, but so far what I've heard and what I've read, it is not convincing to me.

*Petroleum News: The other argument against what's going on is that it's moving too fast, pushed through committees without enough discussion.*

Doogan: I've got to tell you. The way the House Resources Committee handled the bill was shameful. There was one do pass, two never pass and everybody else was a no recommendation on that bill (four no recommendations and one amend). In talking to my colleagues in that committee, no one seemed to understand what it would do or whether it was a good idea. They sort of got pushed pretty hard by leadership to move that bill along.

*Petroleum News: Aces only took 30 days with three committees on each side hearing the bill, plus a full day of discussion with LB&A before you guys gaveled in. That's pretty quick, too, isn't it?*

Doogan: Yeah, but the issues were a lot more clear cut in ACES. It wasn't complicated. As I sit here now, I've read the bill, I've sat in a couple of committees, I still don't know what it's going to cost the state, or that it's going to cost that much and what it's going to do. The ACES discussion with the exception of in the Senate when you would click in the higher tax rates, it wasn't complicated. It was to that extent to what it was you were doing and what effect it would have.

*Petroleum News: Last year the Legislature found creative ways to drive business to Cook Inlet. Are there some creative options beyond cut this and drop that?*

Doogan: With Cook Inlet, you've got a pretty small basin. You sort of know where you are likely to find oil and gas. The problems there aren't discovering stuff. The problem is what do you do with it, once you've got it. Right now we are producing more oil and gas than we can absorb. Once the plant in Kenai shuts down, you're going to have a lot more hydrocarbons than you'll know what to do with. The problem we've got on the North Slope is that the oil production keeps going down 5, 6 or 7 percent every year. That's going to be a problem because you're not going to be able to run the pipeline. State revenue, employment, a lot of things are going to suffer because of that. There is the possibility you are going to produce oil offshore. That oil is presumptively, they will have to build a spur and run that oil down the trans-Alaska pipeline. If you are capable of doing any production in NPR-A, that's still more oil. Then you've got heavy oil. The situation on the North Slope is not that there is not enough oil. The problem is the producers want more money to produce it. That's not a function of their cost, though it will be more expensive to produce the heavy oil. What they want is a lot more money to do what they would do otherwise. Their rap is Alaska, you're pricing yourself out of the market. My response is good luck producing that oil on Sakhalin Island when the political system goes south. Have fun in Venezuela. Have a good time when you're in places when you've got to airlift your employees out of the area because they are getting shot at.

*Petroleum News: You've got feuds with the federal government. Every state has them. But these feuds, regardless of what side of resource argument you're on, it inhibits the state's ability to put oil in the pipeline. What would you like to see this administration do?*

Doogan: It needs to take a more realistic view of what oil production in Alaska is. Among other things, how it is now. It's pretty cheap oil. It's very secure oil. It's expandable oil. You can get more if you put more effort into it. A national

see **DOOGAN Q&A** page 7




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● GOVERNMENT

# Canada's northern regulatory cost burden

**By GARY PARK**

*For Petroleum News*

The Canadian government is pondering ways to improve its northern regulatory processes, a federal official told a northern gas symposium in Calgary earlier in March where participants got a detailed insight into the costs and challenges faced by E&P companies.

Stephen Traynor, director of resource policy and programs for Indian and Northern Affairs Canada, said an action plan announced last May by then-Indian and Northern Affairs Minister Chuck Strahl has been allocated C$11 million over two years to achieve a more efficient and effective regime through legislative and regulatory change.

He said environmental monitoring programs will also be enhanced in the Northwest Territories and Nunavut, where C$8 million will be spent over two years.

Whatever change occurs can't come too soon based on a presentation to the symposium by John Hogg, vice president of exploration and operations at MGM Energy.

Based on his 30 years' experience in Canada's North, he said the last three decades have spawned a "significant amount of regulatory overlap and confusion."

## Opportunity for a fix

But the current exploration hiatus, pending a decision on the Mackenzie Gas Project, provides an opportunity to fix those problems, otherwise "neither the regulators nor the industry will have time to do it," Hogg said.

Topping his action list would be the introduction of a single set of seismic acquisition guidelines in the Northwest Territories, ending the current multilayered approval process involving the NWT government, NWT Water Board and National Energy Board.

He also called for a "made in NWT" method of handling liquid and solid waste.

Hogg estimated the cost of exploring in the Mackenzie Delta is about five times the cost in British Columbia and Alberta, given the shortage of oilfield services in the north and the confined drilling season of about three months.

Obtaining a permit for any drilling or seismic program is more than C$250,000, Hogg said, adding: "Both the regulatory cost and the timelines are, we think, a deterrent to industry and there are many regulators (federal, territorial and local) compared to other Canadian regimes."

He said approval for an exploratory well in the NWT can take six to 15 months, compared with six to eight weeks in Alberta, while permitting a seismic program can take four to 12 months in the north, compared with two months in Western Canada. ●

*Contact Gary Park through publisher@petroleumnews.com*

● FINANCE & ECONOMY

# Parnell: Investment goal of tax change

*Governor defends changes in ACES, calls $10 billion loss 'fantasy scenario' based on no increased investment, no legislative action*

**By KRISTEN NELSON**

*Petroleum News*

Making Alaska more competitive for oil and gas investment is the goal of tax changes the administration is pushing in the Legislature. If enacted, the charges are expected to reduce revenues to the state in the initial years, a focal point of concern for legislators opposing the governor's bill.

The administration projects more investment in the state as a result of lowering the state's production tax, resulting in more production and revenues in the long term.

JUDY PATRICK

GOV. SEAN PARNELL

Gov. Sean Parnell said at a March 11 press availability that a $10 billion multi-year loss in state revenue cited by one senator is "kind of a fantasy scenario," which assumes "that no new activity occurs" and that faced with lowered taxes which produce no new activity, the Legislature would take no action for 10 years.

"I don't assume that. I assume that lower taxes means we're more competitive and companies come in," the governor said.

If lowering the state's oil and gas taxes doesn't bring in more companies, "you can bet the Legislature will change it," he said.

An amended version of the governor's bill passed the House Resources Committee and is in what is projected to be a two-week hearing in the House Finance Committee. Senate Resources is just beginning Senate hearings on the bill, which has a referral to the Senate Finance Committee.

## Average at $60 oil prices

Alaska's current oil and gas tax regime is about average when oil prices are at $60 a barrel, Parnell said, "But when oil prices get up there over 100 bucks a barrel we are a complete outlier."

"And so what I'm suggesting is that let's be competitive; … let's put ourselves in the game instead of taking ourselves out of the game at those high oil prices."

Parnell said that while he supported the current tax regime, Alaska's Clear and Equitable Share or ACES, when it was introduced in 2007, compromises were made in the Legislature.

"In hindsight, I think the progressivity curve is too steep," he said.

Proposed changes this year put a ceiling on progressivity, the rate by which taxes increase as the price of oil drives net revenues up, and add a reduced base rate for new fields.

## Progressivity bracketed

Progressivity is also bracketed in the governor's bill. The bracket proposal for progressivity is like that in U.S. tax rates: A given rate is charged on the first portion of income; higher rates are only paid on portions of higher income.

Under ACES, progressivity affects all taxable income. As the price of oil drives net profits higher, all profits are taxed at the highest rate.

"We are collecting an extreme amount of money compared to other jurisdictions at those high oil prices," Parnell said.

"There no way that we can be as competitive at these higher prices."

The state has a world-class resource and unless its tax rate is competitive, the state won't attract capital to develop that resource, he said.

*Alaska's current oil and gas tax regime is about average when oil prices are at $60 a barrel, "But when oil prices get up there over 100 bucks a barrel we are a complete outlier."*

**—Alaska Gov. Sean Parnell**

## Parachute going down

The bill breaks out new production — from fields that aren't currently in units — for a lower base tax rate, 15 percent compared to 25 percent for existing fields, to encourage exploration.

But Parnell also pointed to opportunities in existing fields for production of mid-gravity and heavy oil, which isn't exploration, but development within existing fields.

"But that is high cost type work that won't get done with those dollars when those dollars can get a greater return somewhere else."

"I don't think we should be holding on and squeezing every last drop out of existing production, because that's a parachute that's going down," he said. Instead the state needs to create new opportunities for future generations.

Parnell said passing the oil tax changes this year is vital.

"Why wait for jobs? Why wait another year for investment? Why wait another year to help fill this pipeline?" he asked.

"There's no reason to wait and you know we cannot sit here and play political games with Alaska's future; we've got to have a plan forward."

## Uncertain passage

House Majority Leader Alan Austerman, R-Kodiak, said March 14 at the House Majority press availability that it is his impression that there are enough votes in the House to pass the bill.

Whether there would be time for the bill to move through the Senate this session is

see **TAX DEBATE** *page 6*

● ALTERNATIVE ENERGY

# Troubled Alaska power utility forges on

*Naknek Electric, mired in bankruptcy, obtains permit to drill second geothermal well as flow testing continues on initial hole*

**By WESLEY LOY**
*For Petroleum News*

A small electric cooperative in southwestern Alaska has obtained a state permit to drill a second geothermal well.

Meanwhile, work continues on the utility's first well — a project that forced the Naknek Electric Association into Chapter 11 bankruptcy reorganization due to cost overruns.

The co-op is attempting to forge ahead in hopes of establishing a geothermal energy source, providing relief from the high cost of diesel to generate electricity.

Naknek Electric serves the villages of King Salmon, Naknek and South Naknek in the salmon-rich Bristol Bay region.

### Testing first well

A challenge for the utility has been perfecting its first well, to include flushing out drilling mud and cuttings and testing the well's flow and temperature to determine its strength as a geothermal producer.

*The report indicates it's not yet clear whether Naknek Electric is on a successful "geothermal path," or will end up with an "all diesel outcome."*

To complete the job, Naknek Electric needed to borrow additional money despite its bankruptcy filing.

In December, a bankruptcy judge in Anchorage approved a $1.5 million loan from the National Rural Utilities Cooperative Finance Corp., a private, nonprofit lender based in Herndon, Va.

The same lender financed Naknek Electric's purchase of a rig to carry out the co-op's plan to drill multiple geothermal wells.

According to a "status report" the co-op filed Feb. 24 in the bankruptcy court, Naknek Electric used the loan to purchase, ship and operate a compressor and air booster to clean out the well.

"Over the last three weeks, the Debtor has boosted water from as deep as 4,500 feet and expects to reach the 7,000 feet level and the slotted liner within the next week," the status report said. "The water being pumped from the well is very dirty — the Debtor believes that is a good sign."

The report indicates it's not yet clear whether Naknek Electric is on a successful "geothermal path," or will end up with an "all diesel outcome."

### Permit for second well approved

The Alaska Oil and Gas Conservation Commission, which regulates drilling, on Feb. 8 approved a permit for a second exploratory geothermal well — the Naknek G-2 well.

But drilling has not yet begun on the second well, as the rig remains over the G-1 well while testing proceeds, said Erik LeRoy, an Anchorage attorney representing Naknek Electric in the bankruptcy case.

"Within a month, we'll have the answer as to whether we have a viable well there," LeRoy told Petroleum News.

The G-1 well site is a few miles northeast of King Salmon.

Naknek Electric doesn't yet have the financing to start a second well, LeRoy said.

But the co-op has mapped out a plan to obtain financing. In court filings, the utility has said it intends to apply for a $52 million loan guarantee from the U.S. Department of Agriculture's Rural Utilities Service.

The co-op would then apply to the Federal Financing Bank, a government corporation, for a loan backed by the Rural Utilities Service guarantee, the Feb. 24 status report said.

Naknek Electric filed for Chapter 11 protection from creditors on Sept. 29, 2010, citing assets of $10 million to $50 million and liabilities in the same range. Unexpected costs and other problems with the geothermal drilling venture precipitated the filing.

The co-op began looking at geothermal several years ago, as the boundary of the volcanic Katmai National Park and Preserve is just a few miles from NEA's electric lines.

Its vision is to build a 10-megawatt geothermal power plant to supply villages in the region.

The co-op's residential and business members in December took a vote signaling continued support for the geothermal project. ●

*Contact Wesley Loy at wloy@petroleumnews.com*



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## TAX DEBATE

another issue.

Senate Finance Committee co-Chair Bert Stedman, R-Sitka, has said that there are reports on fiscal issues which won't be ready until June, well after the end of the session April 17.

Austerman said the Legislature probably wouldn't call itself back into session — a situation in which all issues are on the table — but would wait for the governor to call a special session and set the agenda.

He said that if the ACES revision passes the House and the Senate is just a few days from completion, "it could happen that we extend the session." But if the reports are needed or if the bill is bogged down in the Senate, Austerman said, a special session later in the summer makes sense.

He said preliminary discussions indicate a preference for waiting until after the reports are in, or just before they are due so that the Legislature would be in session when they come out. ●

*Contact Kristen Nelson at knelson@petroleumnews.com*

● PIPELINES & DOWNSTREAM

# Industry watchdog doing maintenance audit

*Review will assess upkeep at Valdez Marine Terminal; former Alyeska Pipeline executive Dan Hisey hired to write report due in June*

**By WESLEY LOY**

*For Petroleum News*

A nonprofit organization that acts as watchdog over Alaska's oil tanker port at Valdez is undertaking a "maintenance audit" of the facility.

The Valdez Marine Terminal is where tank ships pick up loads of North Slope crude oil for delivery to predominantly West Coast refineries.

The Prince William Sound Regional Citizens' Advisory Council, based in Valdez, decided at its September 2010 board meeting to conduct the audit of maintenance practices at the terminal.

Recent problems along the 800-mile oil pipeline that ends at Valdez helped inspire the maintenance audit, said RCAC spokesman Stan Jones.

Those problems include an extended shutdown of the pipeline in January following discovery of an oil leak at Pump Station 1 on the North Slope, and an overflow of crude from a holding tank in May 2010 at Pump Station 9 south of Fairbanks.

The RCAC, a congressionally mandated organization created after the 1989 Exxon Valdez oil spill, doesn't have oversight of the pipeline, just the terminal.

The council says it has identified a number of maintenance concerns at the facility.

Anchorage-based Alyeska Pipeline Service Co. operates both the pipeline and terminal on behalf of owners BP, ConocoPhillips, ExxonMobil, Chevron and Koch Industries.

An Alyeska spokeswoman did not respond to a request for comment on the maintenance audit.

### Two-stage review

"Staff and volunteers became concerned about the status of maintenance at the VMT after a number of perhaps maintenance issues became visible," an RCAC briefing paper on the maintenance audit says. "As a whole, these concerns appear to be associated with deferral of preventive maintenance."

DAVID PREDEGER

**The Valdez Marine Terminal**

The concerns have to do with certain valves, the terminal's electrical systems, the loading arms that deliver crude to tankers, the condition of storage tanks and the integrity of "secondary containment cells."

The briefing paper also notes "the considerable turnover in VMT staff during the past three years."

Jones said the maintenance audit will occur in two stages. First will be a review of maintenance "paperwork" to gain a sense of terminal upkeep.

Then comes selection of a couple of major systems at the terminal for a closer, physical examination, Jones said.

The RCAC has committed $102,800 for the maintenance audit, to come from the organization's existing budget. The RCAC operates mainly on the approximately $3 million it receives annually from Alyeska.

Under its contract with Alyeska, the RCAC's board, staff and contractors have access to Alyeska's records and facilities, Jones said.

### Hisey hired

The RCAC has awarded a contract to Dan Hisey of Bellingham, Wash., to conduct the maintenance audit.

> *"Staff and volunteers became concerned about the status of maintenance at the VMT after a number of perhaps maintenance issues became visible."*
>
> **—RCAC briefing paper on the maintenance audit**

Hisey is quite familiar with the terminal, having previously worked as chief operating officer for Alyeska. He left the firm in 2005.

In a March 15 interview with Petroleum News, Hisey said Alyeska, when it renewed the pipeline right of way in 2003 for another 30 years of operation, adopted a process known as "reliability-centered maintenance" or RCM. It was a step Hisey said he endorsed while at Alyeska.

RCM is a respected maintenance strategy generally defined as a way to ensure that assets keep doing what their users want them to do.

The maintenance audit will seek to verify that systems at the Valdez Marine Terminal are receiving proper maintenance either through RCM, for the larger systems, or "other maintenance paradigms" used for smaller and less complicated systems, the RCAC's briefing paper says.

Hisey said he didn't have any specific systems in mind for up-close examination.

Some important systems at the terminal deal with power generation, vapor control, treatment of ballast water from tankers and the berth loading arms.

Another former Alyeska manager, Darryl Hammond, will help with the maintenance audit. Hisey said Hammond, who retired from Alyeska in December 2010, spent years working with RCM on the pipeline.

Hisey said he's hopeful the maintenance audit will be useful not only for the RCAC, but for Alyeska as well.

The final audit report is expected by June 30. ●

*Contact Wesley Loy at wloy@petroleumnews.com*

*continued from page 4*

## DOOGAN Q&A

administration says, 'we know we've got this oil, we know it can be produced, we know it will lower our dependence. But we're going to do it (impede production) anyway.' Well, you've got to wonder, who is doing the thinking?

*Petroleum News: You didn't go to energy council. I know you don't do a lot of travel but you are on LB&A and on House Finance, which are on the front lines of important decisions. Why didn't you go?*

Doogan: The decisions that I am involved with, the decisions I sort of got a piece of are not decisions that are related to what happens at the Energy Council. The decisions dictated by the federal government are a separate set of decisions from the decisions that I have any purchase over. It doesn't help me I guess is my answer. I haven't learned anything that helped me do the job I'm elected to. It didn't seem to me to be a worthwhile use of my time particularly when I could use the time to go back to my district and talk to people about things important to them.

*Petroleum News: Can the state afford to live on $2 billion less each year?*

Doogan: The answer is no, depending on what the price of oil is 18 months from now, or yes, depending on that price today, which is $117 a barrel as we sit here. If it gets down below between $80 to $85 a barrel, it ain't going to be cheap no matter what. If something bad happens in Saudi Arabia or Libya gets wrapped around the axel that they can't produce oil anymore those values are going to go up.

*Petroleum News: I ask because at one time not long ago, the state did live on less.*

Doogan: Sure, we could get along with substantially less money. We've increased the budget on an average of 10 percent a year I think eight years now. I'm just talking about the operating budget. Can we get by on less than that, sure we could. Do all of the people who are beneficiates of some of this money want to have to do that, no they don't. That's why these budgets keep going up. Can it go down, sure. Would it get ugly, yes it will. Anyone who can recall when things went gunnysack in the late '80s will tell you that was not very much fun. Having money is more fun than not having money. A lot less fussing and fighting. Would it be doable to dial back, sure. Does anyone want to, I doubt it.

*Petroleum News: Has anyone told you where this money is going to come from? Have you been asked that when you go home?*

Doogan: I've had people question essentially if you guys are going to do that, how do you finance it. Ether you get really lucky in the roulette game we play with oil values or you end up taking the current surplus and throwing it at the oil industry and hoping something good happens. The people who are engaged in this system we've got here — like people who run schools districts — are watching this very carefully because they are afraid their stuff has to be cut so we can make our friends at BP happy. ●

## EXPLORATION & PRODUCTION

### Doyon plans new Nenana seismic survey

As part of a continuing search for oil and natural gas in the Nenana basin, in Interior Alaska, about 50 miles southwest of Fairbanks, Doyon Ltd. is planning to carry out a 2-D seismic survey in the northern part of the basin during the winter of 2012, the Alaska Native regional corporation said March 16. Doyon will primarily conduct the survey on state land within the area of a state exploration license that Doyon holds. However, some Doyon-owned land and some land owned by Toghotthele Corp., the village corporation for the Nenana village, may be involved in the survey, Doyon said.

A partnership consisting of Doyon, Rampart Energy Co., Arctic Slope Regional Corp., Usibelli Energy LLC and Cedar Creek Oil & Gas Co. has been conducting an exploration program in the Nenana basin and in 2009 drilled the 11,000-foot Nunivak No. 1 well near Nenana. Doyon says that, although that well demonstrated the existence of an active petroleum system in the basin, the well did not encounter an economic accumulation of natural gas.

Doyon says that it has taken over from Rampart as operator of the Nenana exploration program and that, so far, Doyon is the only member of the partnership to commit to the new seismic survey. The regional corporation says that it is prepared to proceed with the survey without the participation of some or all or the other members of the partnership.

James Mery, Doyon senior vice president, lands and natural resources, told Petroleum News March 16 that the northern part of the basin, where the new survey will take place, is the deepest and broadest part of the basin. Analogous freshwater basins elsewhere in the world tend to have some of their most prolific petroleum plays in the basin centers, Mery said.

Doyon has licensed and re-interpreted some gravity and magnetic data for the basin, but there is no existing seismic data for the northern part of the basin, he said.

—ALAN BAILEY



● FINANCE & ECONOMY

# Marks: Progressivity dysfunctional

*Petroleum economist, contracting for LB&A, tells legislators Alaska not competitive for investment with comparable oil provinces*

By KRISTEN NELSON
*Petroleum News*

Petroleum economist Roger Marks, under contract to the Alaska Legislature's Budget and Audit Committee, told the House Finance Committee March 15 that he believes the progressivity structure within ACES is dysfunctional.

He said this has concerned him since progressivity was enacted as part of the Petroleum Production Tax in 2006. ACES, Alaska's Clear and Equitable Share, enacted in 2007, made progressivity more aggressive, Marks said.

Marks was testifying on House Bill 110, Gov. Sean Parnell's proposal to reduce oil and gas taxes by changing how progressivity is applied, capping it and establishing a lower base rate for new fields.

There's nothing wrong with the principle of progressivity, Marks said — you pay less tax when you have less income and more tax when you have more income. But progressivity in Alaska's tax system is not like the bracketed system in the U.S. tax code for individual taxpayers, where higher tax levels only apply to incremental amounts of income.

With ACES, when progressivity kicks in at net profits above $30 a barrel on crude oil, the highest rate is applied to every dollar of value.

*As for fixing ACES, Marks told legislators he doesn't believe you can fix ACES with more credits: Tax dwarfs credits, he said.*

This is reflected in the marginal tax rate, he said: at $90 a barrel the marginal tax rate is 80 percent, so producers get only 20 cents of the marginal dollar from 89 to 90.

Because of the high marginal tax rate, Marks said, producers don't make that much money as prices go up. That's a problem because when producers evaluate projects they look to the high side and with that high side suppressed in ACES, a project might not happen.

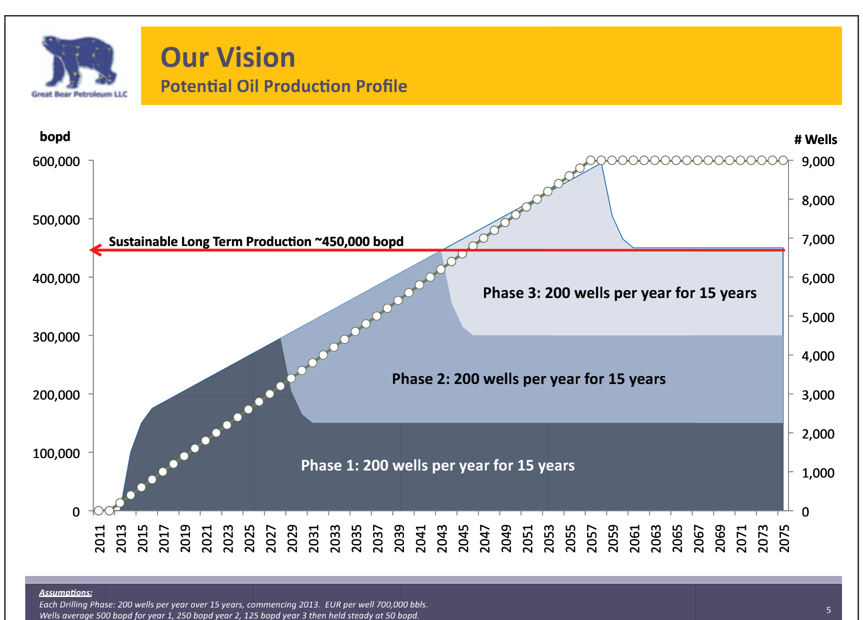
#### Alaska v. other jurisdictions

Marks compared Alaska to a group of jurisdiction based on comparable tax and royalty regimes (as opposed to jurisdictions with production sharing regimes) and comparable resources. Except for Alaska, he said, none of these have progressivity. And at $100 a barrel, Alaska's rate is the highest except for Norway, where most of the equity production is owned by Statoil

see MARKS page 25


Steeply dipping panel of Cretaceous pebble shale unit, GRZ, and Hue Shale at Hue Creek in ANWR. Rusty brown and orange weathering is characteristic of tuffaceous intervals in this succession. Stratigraphic younging direction is to the right. View to west.

P.L. DECKER, 2005




● LAND & LEASING

# Duncan: Our timing was fortuitous

*Great Bear carefully selected shale oil acreage won in 2010 North Slope areawide lease sale; prize was three of richest source rocks in world*

**By KAY CASHMAN**

*Petroleum News*

According to Great Bear Petroleum's top executive, Alaska has three of the most prolific, world class, source rocks in the world. Individually, Ed Duncan says, "as source rocks, they are superior to the Eagle Ford shale play in Texas, currently considered the hottest conventional oil play in the world."

As for Eagle Ford being the hottest shale oil play, he says, "We believe that is about to change."

Great Bear entered Alaska in October by placing winning bids on more than 500,000 acres in the State of Alaska's annual North Slope lease sale,

see **GREAT BEAR TIMING** page 18

● EXPLORATION & PRODUCTION

# Why Alaska sees hope in source rocks

*State petroleum geologist tells lawmakers that North Slope source rocks resemble some of the hottest shale plays in North America*

**By ERIC LIDJI**

*For Petroleum News*

The State of Alaska is "cautiously optimistic" about oil development from source rocks.

"Optimistic" because the geology of the Alaska North Slope resembles the hot Eagle Ford shale formation in South Texas, and Great Bear Petroleum's leases are "well positioned" to develop that geology, a Division of Oil and Gas petroleum geologist recently told state lawmakers. "Cautiously" because developing source rocks is an entirely new concept in Alaska that will require a lot of equipment, crews and water, and some trial and error.

"If these production pilots and exploration success do occur then full-scale development, if it were to occur, could be quite a whirlwind," Paul Decker said on Feb. 23. "But, you know, things remain to be seen. But at this point I think we're cautiously optimistic."

The play Great Bear is proposing to develop at its new 537,500-acre North Slope lease position is so new for Alaska that it doesn't even have an agreed upon name, but Decker is calling it "source-reservoired oil," meaning that the source rock is also the reservoir, because the rocks are so tight that they hold onto the oil they generate like a traditional geologic trap.

### What makes for good rocks?

The North Slope is home to three "prolific" source rock intervals that are candidates for development: the Shublik, the Kingak and the GRZ/Hue shale system, from deepest to shallowest. These source rocks exist some 8,000 to 13,000 feet underground.

The factors that make source rocks good candidates for development include the organic chemistry — the ingredients for making oil, elements like carbon and hydrogen — and the thermal maturity — the underground heat needed to turn those elements into oil.

For source rocks to become the "kitchen" where oil and gas gets "cooked," they must be deep enough for the heat of the earth to reach the proper temperatures. Shallow rocks are too cool, or "immature," and won't generate oil and gas for ages, but in the hotter depths below those immature rocks are usually an "oil window" and a deeper "gas window."

The tectonic history is also important, because natural fracturing can make recovery easier and needs to be well understood in order to design, drill, and complete the

see **SOURCE ROCKS** page 19

● EXPLORATION & PRODUCTION

# Oil makes a grab for shale crown

*Lower 48 shale game started out as gas play, but low gas prices, new technology have firms chasing higher value oil, natural gas liquids*

**By ERIC LIDJI**
*For Petroleum News*

The potential for a shale oil boom on the North Slope of Alaska is based on slightly different market factors than the current rush on similar formations across the Lower 48.

The interest in oil-bearing source rocks on the North Slope is based in part of infrastructure. The lack of a natural gas pipeline makes oil the only sure bet in northern Alaska, while declining throughput on the trans-Alaska oil pipeline is creating an incentive — and a public need — for producers to find new volumes of oil.

In the Lower 48, though, recent interest in shale oil is about prices. When shale gas exploration exploded in 2008, oil topped $150 a barrel and natural gas topped $13 per thousand cubic feet, but today oil is $100 a barrel and natural gas is less than $4 per mcf.

Oil has always been more valuable than gas, but technological constraints kept companies from pursuing it until Petrohawk cracked the code in the Eagle Ford in 2008.

The recent shift became clear as companies released their annual reports this year.

Chesapeake Energy, which calls itself "America's Champion of Natural Gas," doubled its oil production in 2010 and said it didn't plan to transition away from oil even if natural gas prices improve in the next few years. "We can drill a natural gas well and receive around $4 per unit of production or we can drill an oil well and receive around $15 per unit of production," CEO Aubrey McClendon told investors in late February.

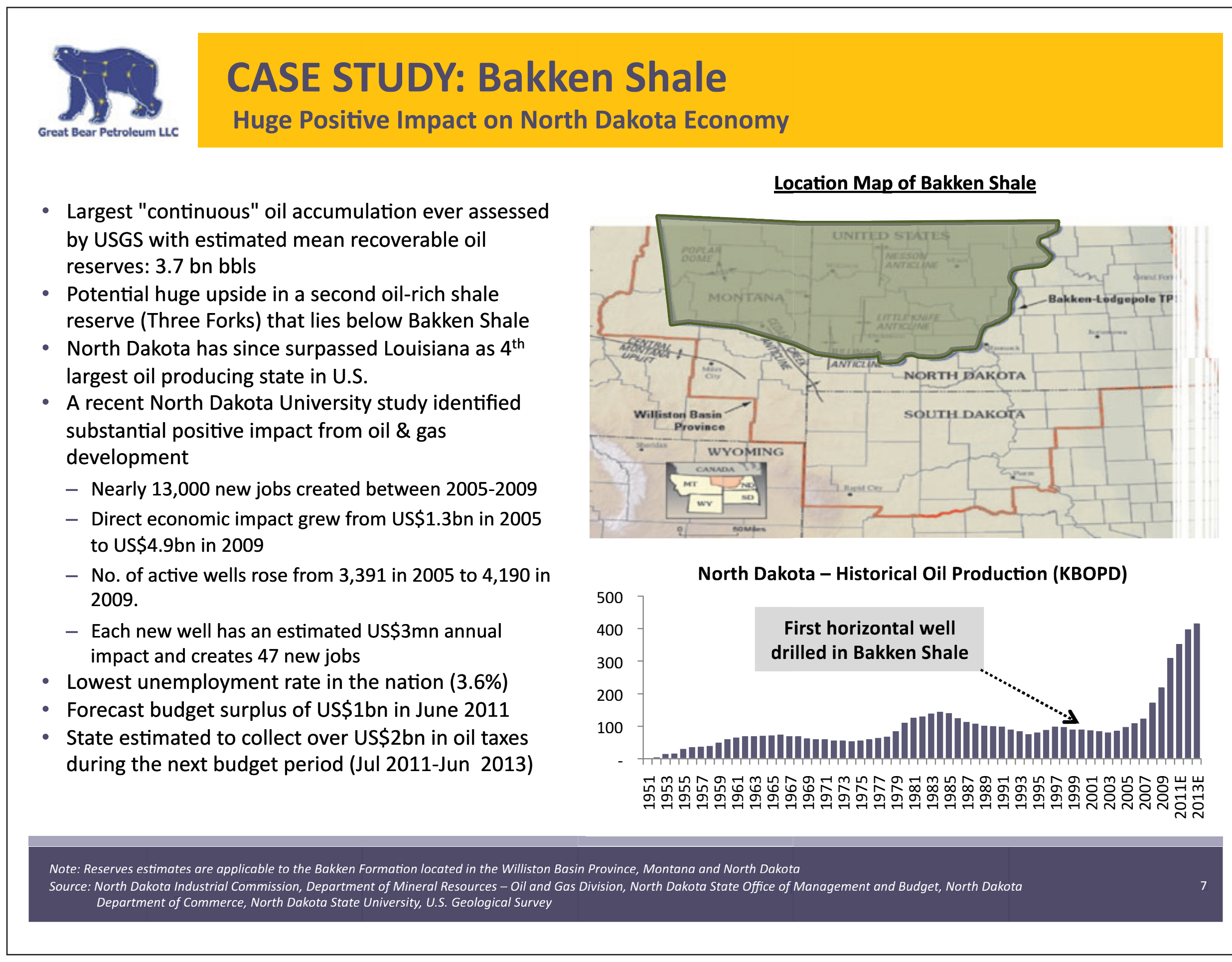
**"We can drill a natural gas well and receive around $4 per unit of production or we can drill an oil well and receive around $15 per unit of production." —Aubrey McClendon, CEO of Chesapeake Energy**

Range Resources recently sold its Barnett Shale properties in North Texas to focus on Appalachia, where three stacked shale plays — the Marcellus, Upper Devonian and Utica — create economies of scale by offering liquids-rich shale gas formations.

After watching gas volumes drop except at liquids-rich plays like the Granite Wash tight sands in Oklahoma, MarkWest Energy Partners, a midstream company, wants to connect liquids operations from Pennsylvania through Kentucky and down to Gulf Coast markets.

The major service companies see the writing on the wall, too. "With natural gas price forecasts from the Energy Information Agency for 2011 slipping by nearly a third compared to initial projections made at the beginning of the year, an increasing portion of the drilling and completion activity in shale reservoirs has shifted to liquid and condensate-rich plays in North America," Schlumberger wrote in year-end filings.

Baker Hughes noted that recent spending on shale gas is based on temporary market oddities: hedging leftover from times of higher prices, the need to drill wells to meet lease terms, joint venture capital coming from overseas companies looking to gain technical know-how and experience and boosts from associated liquids production.




## Cracking the nut

To tap natural gas trapped in underground source rock (mostly shale) where hydrocarbons are trapped (only a small percentage ever escapes), producers drill down and horizontally into the tight rock, then pump water, sand and chemicals into the hole to crack the shale and allow natural gas to flow up.

Because oil molecules are sticky and larger than gas molecules, engineers thought the process wouldn't work to squeeze oil out fast enough to make it economical. But drillers learned how to increase the number of cracks in the rock and use different chemicals to free up oil at low cost.

"We've completely transformed the natural gas industry, and I wouldn't be surprised if we transform the oil business in the next few years too," McClendon said.

Petroleum engineers first used the method to unlock oil from source rock in 2007 from the Bakken Shale, a 25,000-square-mile formation under North Dakota and Montana.

A huge increase in interest followed a 2008 U.S. Geologic Survey study suggesting that the Bakken contained 3 billion to 4.3 billion barrels of oil, a 25-fold increase over the previous USGS estimate, made in 1995.

That increase is the result of one word: recoverable. Improvements in technology between 1995 and 2008 made it possible for companies to first extract natural gas and the, in 2007, begin to extract liquids.

## On to the Eagle Ford shale

Once the odd-man-out as an oily shale play, the Bakken is now a trailblazer. Producers are increasingly focused on the oil and natural gas liquids potential of shale gas plays.

Liquid production doubled in the Barnett between 2005 and 2009, nearly quadrupled in the Marcellus between 2008 and 2009, and increased eight-fold in the Woodford shale of Oklahoma between 2007 and 2009.

In just this past year liquids production in the Bakken rose 50 percent to 458,000 barrels a day, according to Bentek Energy, an energy analysis firm.

In the Eagle Ford shale of South Texas, oil production jumped from 300,000 barrels in 2009 to nearly 2.6 million barrels in 2010 and condensate production jumped from some 500,000 barrels in 2009 to nearly 3.3 million barrels in 2010, according to the Railroad Commission of Texas, the main permitting and statistical agency in the state. Those increases dwarf the not-too-shabby four-fold jump in natural gas production last year.

*see* **SHALE CROWN** *page 11*

● LAND & LEASING

# Great Bear scored, but didn't win it all

*Although Great Bear well-positioned, Duncan and Decker say there's plenty of room for other players in North Slope shale plays*

**By KAY CASHMAN**
*Petroleum News*

Will there be room for other companies to develop shale plays on Alaska's North Slope or did Great Bear Petroleum win most of the acreage in the oil maturation window?

"By no means did Great Bear win all of the acreage that would be prospective, that would appear to be in the oil maturation window," Alaska Division of Oil and Gas geologist Paul Decker told Petroleum News.

"I think they are very well-positioned geologically," he said, referring to the 500,000 acres-plus the newly formed independent was high bidder on in the October State of Alaska North Slope oil and gas lease sale. (See maps on page 19.)

But it's "a question of geology versus 'close-ology,'" Decker said. "Based on thermal maturity, the North Slope source rock plays likely extend far beyond Great Bear's acreage position, particularly to the west. However, from the perspective of needing to build out year-round access and infrastructure tie-backs, someplace very close to the Dalton Highway, TAPS, and producing fields would seem a logical place to start," and Great Bear's acreage brackets both the Dalton Highway (Haul Road) and the nearby trans-Alaska oil pipeline, Decker said.

Great Bear President Ed Duncan gave Petroleum News a similar answer when asked f there was room for other players.

Yes, there's no doubt there is room for others," Duncan said.

"We carefully selected all our acreage," paying close attention to the maturity of the rock, making sure it was in the oil window. "We won exactly what we wanted, as much as we wanted. We'll be busy with it for the rest of my life, and probably longer," he said.

## Next North Slope lease sale

So what about the next North Slope lease sale? In their planning for the October 2011 sale, Division of Oil and Gas officials asked Duncan what he thinks the next lease sale will look like.

In fact, division Director Kevin Banks has his people studying what will make state lease sales better for bidders interested in source rock plays.

Here is what Duncan said he told division officials: "There will be starry eyed speculators; there will be companies that have ability to think about what this play actually is and understand the technological drivers and bid in an intelligent way; and there will be some in between." ●

*Contact Kay Cashman at publisher@petroleumnews.com*



*continued from page 10*

## SHALE CROWN

The Eagle Ford is still just a kid. Petrohawk began developing the gas potential of the formation in 2008, but it and others have since focused on the liquids-rich northeast end of the 400-mile long formation starting from the Mexican border up into East Texas.

The Eagle Ford is attractive because its rocks, buried 4,000 to 12,000 feet underground, are up to 70 percent carbonate shale, making them very brittle and easy to fracture.

That combined with rising oil prices is drawing producers to the region. The Railroad Commission of Texas issued 33 drilling permits in 2008, 94 in 2009 and 1,229 in 2010.

That activity is expected to increase and to keep favoring oil. A February 2011 industry-funded forecast by the University of Texas San Antonio expects companies to drill nearly 5,000 new wells in the Eagle Ford over the next decade, nearly 75 percent of them for oil.

The producers stalking the Eagle Ford include some of the biggest players in Alaska, like Anadarko Petroleum, ConocoPhillips, Marathon Oil and Pioneer Natural Resources.

While that means Alaska is competing with South Texas for exploration dollars, it also means those companies are learning about similar geology — the Eagle Ford is thought to be the closest analog to the Shublik and Kingak, the North Slope's major source rocks. ●

*Contact Eric Lidji at ericlidji@mac.com*

● EXPLORATION & PRODUCTION

# Brooks Range joins Alaska shale game

*Local independent has 100,000 acres-plus under lease on North Slope in maturation window of two or three world class source rocks*

By KAY CASHMAN

*Petroleum News*

An Alaska-based joint venture that is drilling the state's only exploration well on the North Slope this winter says it has more than 100,000 acres under lease west of the Kuparuk oil field in the maturation window of two, possibly three, world class source rocks — the Shublik, Kingak and possibly the HRZ shales.

Ken Thompson, managing director of Alaska Venture Capital Group, or AVCG, conversed via e-mail with Petroleum News in mid-March about the company's plans to find a partner with capital and expertise in Lower 48 shale plays.

In 2006, AVCG formed the joint venture and formed Brooks Range Petroleum Corp., or BRPC, the Alaska operating entity for the working interest owners, who are currently Kansas-based AVCG, which holds a 50 percent working interest in the JV's 240,000 acres on the North Slope and nearshore Beaufort Sea; TG World Energy, a small Calgary public corporation; and Ramshorn Investments, a wholly owned subsidiary of Nabors Drilling USA, out of Houston.

KEN THOMPSON

The new partner will replace Calgary-based Bow Valley Energy Ltd.

"About a year ago or so, we had a company that was a great partner of ours out of Calgary called Bow Valley," Thompson told Alaska lawmakers in February. "Bow Valley was a small public company. It was acquired by another larger public company in the UK, out of England, called Dana Petroleum."

Dana Petroleum came to "the conclusion that the fiscal regime in Alaska was tougher than the UK … and so they decided to focus solely on the UK and told us they did not want to invest in Alaska, so we acquired their interest (about 20 percent), running our interest from 30 percent up to the current 50 percent," Thompson said.

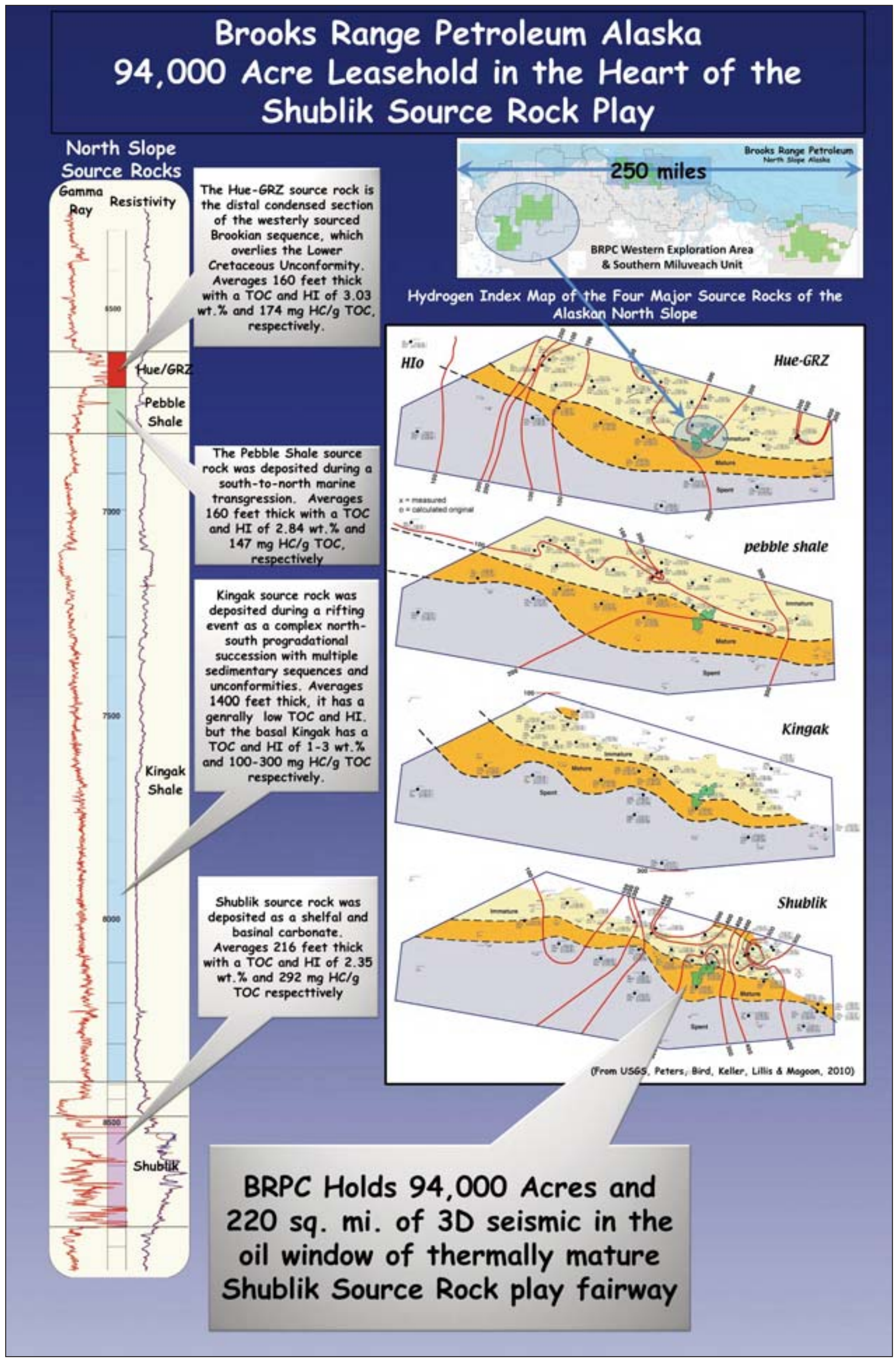
## Looking for a partner with shale oil expertise

"My job in the last … nine months has been to pound the pavement, make a lot of contacts and get our … next investor … that can bring capital, as well as expertise, to us."

In the same period of time the partners were assessing their acreage for source rock potential, Thompson told lawmakers.

"Starting with our working interest owners' meeting in Anchorage on July 20, 2010, we discussed the source rock potential and began some of our geologic assessment on AVCG et al acreage and surrounding areas. We feel our JV's almost 100,000 acres to the west around Tofkat, Big Island and even our Southern Miluveach unit area has source rock potential being in the right maturation and depth window. And we are also studying source rock and low-permeability

see BROOKS RANGE page 13




BROOKS RANGE PETROLEUM

*continued from page 12*

## BROOKS RANGE

sands potential in our Beechey Point unit," Thompson told Petroleum News March 11, when asked to elaborate on what he and Bart Armfield, vice president of operations for BRPC, told lawmakers Feb. 18 at a House Resources Committee meeting.

Thompson also explained why AVCG and its JV partners did not go after additional acreage with shale oil potential at the State of Alaska's annual North Slope areawide lease sale in October, which was when Great Bear Petroleum entered the state, the highest bidder on more than 500,000 acres.

AVCG and its partners thought they had enough acreage, Thompson said; "To get started in our assessment and possible future development, we thought our JV's almost 100,000 acres out west and overall almost 250,000 acreage spread across the North Slope was enough for our JV budget, so we did not bid aggressively at the last October lease sale."

He also said the JV partners "have made great progress on a comprehensive well log assessment and we plan visual core studies in 2011. Could these source rock shales and/or lower-permeability sands in these areas on the North Slope be the next Bakken or the next Eagle Ford development? AVCG and our JV partners plan to find out!"

### JV's focus on next frontiers

Thompson said AVCG and its partners focus "is on what we call the next frontiers for major developments on the North Slope," which "fall into two categories for what we do."

One, he said, is exploration for smaller fields. Smaller being "in the 25-to-50 million-barrel range," noting it was possible they would find something larger, "but for now we're focused on those.

Both in his days with ARCO and more recently with AVCG, looking at seismic, he "saw a lot of" 25-50 million barrel fields. (Thompson was president of ARCO Alaska before its last president, Kevin O. Meyers; then chairman and CEO of ARCO Alaska and one of four top executive vice presidents at corporate before the company's Alaska assets were sold to Phillips Petroleum and the main company acquired by BP.)

"We believe there's a lot of potential production in low permeability sands; there are a couple of resources, they're more expensive to develop, but on our Southern Miluveach unit to the west … we have identified about 1 billion barrels in place, maybe about only 20 percent of that's recoverable, but it's … more expensive to develop."

The second frontier for major developments that his company and its partners are "excited about" is the "oil-source shales," believing the JV's acreage holds "significant potential" for shale plays.

Other sources of oil on and offshore the North Slope are better suited for the majors, Thompson said, referring to heavy oil extraction and exploration and development in the federal waters of the outer continental shelf of the Beaufort and Chukchi seas.

The BRPC partners talked about the potential of their source rock acreage with more than 75 companies in their booth at the North American Prospect Expo, or NAPE, in February. They were there, Thompson said, "specifically to find a partner to join our JV with the skills, experience and technology in source rock shales as well as completions and stimulations technologies for low-permeability sands."

Company officials also touted "a number of conventional leads and prospects," he said.

### Six companies want more information

Six companies, he said, "have asked BRPC to send them more information and to possibly schedule technical sessions to further review our conventional leads and prospects and the source rock potential"; two were international majors, two large U.S. independents and two small/medium-sized U.S. independents.

"Two more companies — a large independent and small independent — said they may be interested after visiting with their senior management further, and will let us know. Incidentally, all six of the companies that told us at the booth they wanted more information, expressed interest in the unconventional resources montage showing our acreage being in the good maturation windows of the Shublik, Kingak, Pebble Shale and HRZ shale intervals," Thompson said. (See montage adjacent to this article.)

### And then there was the tax issue

A key thing the JV partners manning the NAPE booth heard from "most of the companies that stopped by, including those who want to follow up with us," was that "they would not have stopped — they would have kept on walking by our booth — were it not for reports in the oil industry press about Gov. Parnell's bill to change Alaska's ACES (production) tax structure to be more reasonable.

"In particular," Thompson said in an e-mail to Petroleum News, "they liked the capital tax credits for development ... and lower tax rate and lower rate cap for new fields. We also let the companies know we were hoping for the credits to be reimbursed in a year instead of over two years, which helps independents quickly plow the capital back into seismic and drilling. Extension of the 'small producer tax credit' from May 2016 to May 2021 also attracted interest as a positive for investment.

"Quite honestly, if the Legislature makes progress in March adopting the positive changes to ACES, I believe we'll find the partner we're hoping for with capital and technology. If ACES' changes do not occur, I'm not as positive. Somehow, the State needs to adopt one common goal with industry: 'NO DECLINE.'

"I believe the conventional prospects left on the North Slope, the huge viscous oil base, the large potential in low-permeability sands, and the source rock potential all could add up to a leveling of oil production for the state. Instead of fighting over a fixed pie of revenues, the State of Alaska and industry could each enjoy a fair share of a much bigger pie of revenues," Thompson said.

### Regional, shared processing facilities

In his presentation to Alaska lawmakers, Thompson also brought up the "concept of regional processing facilities that we would like to construct that would allow smaller fields — no matter who operates them — to bring … (their production) into our regional facilities. Now that could be helpful, too, to stopping, leveling the decline."

With the exception of Eni's new Nikaitchuq oil field, all producing fields in northern Alaska are operated by two companies: BP and ConocoPhillips. Although oil production is down, most of the legacy fields are close to, or at, capacity for water and/or natural gas handling, which means the owners of those facilities have to back out their own oil to make room for third party oil. ●

*Contact Kay Cashman at publisher@petroleumnews.com*

● SERVICE & SUPPLY

# Twenty new drilling rigs not impossible

By KAY CASHMAN

*Petroleum News*

If Great Bear Petroleum is to meet its development schedule of 200 wells a year for the next 45 years it will need at least 20 drilling rigs working year-round on its 500,000 acres on Alaska's North Slope.

The rigs will likely have to be specially designed for the company's North Slope shale program, although Alaska rig operators say there are two to three rigs on the Slope now that are capable of drilling the two production test wells Great Bear has planned for first quarter 2012 and its two full production wells for late 2012, all of which are expected to be 9,000 to 11,000 feet deep with 4,000 to 6,000 foot laterals.

There are more rigs that could handle the four core holes the company is looking to drill first, as early as this summer and as late as the end of the year.

### "Tough, but not impossible," says Nabors

Petroleum News asked Dave Hebert at Nabors Alaska Drilling if Nabors could deliver 20 new rigs in 12 months because Great Bear is hoping to sanction development by 2013. Three years ago Nabors delivered the first purpose-built AC rigs for the North Slope in 13 months, from design to delivery. Two years ago the company delivered CDR-2 to ConocoPhillips at Kuparuk; it was the first purpose-built coiled tubing rig designed for the Arctic. It took 18 months, from design to delivery.

Hebert said it would be "tough, but not impossible," to provide a one-year turnaround on rigs for Great Bear.

"A lot would depend on the rig design, and if all 20 rigs were essentially the same. We certainly have a lot of options for rig construction at our disposal," he

see NEW RIGS page 15

● EXPLORATION & PRODUCTION

# Cook Inlet companies eye unconventionals

By KAY CASHMAN

*Petroleum News*

While most of the focus in Alaska is on shale oil plays on the North Slope, at least two oil and gas companies in the Cook Inlet basin are looking at checking out the source rock, or shale, in their acreage — Aurora Gas and Escopeta Oil.

As this section in Petroleum News went into production on March 17 morning (see page 1 article for latest news), Escopeta had loaded the Spartan 151 jack-up rig onto a heavy lift vessel at a dock in Freeport, Texas, and was expecting to set sail for Alaska late that afternoon or the next morning.

Escopeta President Danny Davis told Petroleum News that he intends to check out the source rock in his Kitchen Lights unit wells, while looking for conventional oil and gas targets.

"We're going to take a look at the source rock as best as we can with the jack-up," Davis said. If it looks promising for an unconventional resource play, which is what Great Bear Petroleum is chasing on the North Slope, Escopeta is going to further check it out once it gets a production platform in place.

And at an Anchorage Chamber of Commerce meeting on Feb. 7, Aurora Gas President Scott Pfoff said that last summer Aurora successfully tried using hydraulic fracturing in a well in its Three Mile Creek field. The technique, similar to the "fracking" done in Lower 48 shale gas wells, was applied to the field reservoir in a conventional gas well, with the effect of boosting gas production, Pfoff later told Petroleum News. Aurora hopes to use the same technology in other wells and is also interested in the potential to use modern fracking techniques in other Cook Inlet situations, such as in tight gas sands or perhaps in gas source rocks, Pfoff said.


SCOTT PFOFF


DANNY DAVIS

Aurora has for some time been interested in the potential to develop coalbed methane in and around its leases, especially given that those leases are in remote locations, near the pipeline infrastructure but far from population centers.

Pfoff said the company estimates there is a coalbed methane resource equivalent to at least a 10-year gas supply for Southcentral Alaska just in the areas around Aurora's leases.

"The resource potential is huge," he said, also commenting that any development would need to be carried out in a way that avoids the pitfalls encountered in the past with Alaska coalbed methane proposals. ●

*Contact Kay Cashman at publisher@petroleumnews.com*



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## NEW RIGS

said. "Nabors is capable of doing its own in-house rig engineering and construction at our facility in Canada. We have strong relationships with companies such as NOV-Dreco and Columbia Corp."

Parent Nabors Industries "has companies that manufacture many different drilling rig components such as top drives, pipe handlers and fluid monitoring systems, just to name a few," Hebert said.

"Currently we have 35 rigs under construction construction for delivery between now and mid-2012."

Hebert said Nabors always keeps a significant number of long lead items on order, in the "pipeline," so to speak; items such as "SCRs and VFD equipment and engines and so forth, because we can always use them as maintenance items if the rig construction market slows down."

In the last five years "Nabors Industries has built 220 rigs.

"In addition to the construction options mentioned above," he said, "Nabors has proven itself very successful at using Chinese manufacturing companies to mass produce structural rig components, such as masts and substructures, then fitting them with operational components such as pumps, draw works and electronics here in the states."

So the answer is for 20 rigs in a year: "No small task by any means, but certainly not impossible." ●

*Contact Kay Cashman at publisher@petroleumnews.com*

● EXPLORATION & PRODUCTION

# USGS assessing unconventional resources

*Agency is investigating the Alaska potential for developing unconventional plays such as shale oil, shale gas and coalbed methane*

By **ALAN BAILEY**
*Petroleum News*

While much oil and gas interest in North America has focused recently on new so-called unconventional oil and gas plays, especially involving the extraction of hydrocarbon resources directly from oil and gas shales, the Alaska oil industry has continued along a route of seeking and developing oil from conventional porous and permeable reservoir rocks.

But with Great Bear Petroleum forging ahead with plans to extract oil directly from source rocks on the North Slope, Alaska looks set to join the unconventional oil and gas bandwagon.

And the U.S. Geological Survey, the federal agency that has for many years conducted assessments of Alaska's conventional onshore oil and gas resources, is now turning its attention to estimating how much unconventional oil and gas might be accessible in northern Alaska and in the Cook Inlet basin.

Reprint
This story is a reprint from the Feb. 13, 2011, issue of Petroleum News

The agency hopes to complete its Cook Inlet assessment in the late spring or early summer, and run the numbers for its northern Alaska assessment sometime in the fall, USGS geologist Dave Houseknecht told Petroleum News Feb. 8.

### Trapped in the rock

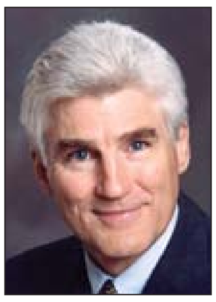
Unlike a conventional oil and gas play, where hydrocarbons migrate into a porous source rock to become trapped under an impervious seal rock, an unconventional play, sometimes referred to as a "continuous" play, involves a rock unit saturated with oil or gas over a broad area, with the fabric of the rock itself, rather than an overlying seal rock, trapping the hydrocarbons in place. The much publicized "fracking" techniques used in this type of play release the hydrocarbons by smashing open the rock fabric.

Estimating the producible volumes of hydrocarbon resources in this type of unconventional play involves assessing three factors: the extent and thickness of the hydrocarbon bearing rock unit; the mechanical and oil production properties of the rock; and the likely success rates for well production from the rock, Houseknecht explained. Essentially, a geologist conducting the assessment will use the rock properties to estimate the sizes of cells from which individual wells might be able to drain hydrocarbons and will use the hydrocarbon production characteristics of the rock to estimate ultimate production volumes for the wells. The geologist will then statistically combine possible ranges of cell sizes and likely production volume ranges, together with ranges in the estimated extent of the complete rock unit, to derive a range of potential, extractable hydrocarbon in the play as a whole.

USGS conducted an assessment of North Slope coalbed methane resources in 2006. And, although there are likely to be substantial unconventional North Slope resources in impermeable, "tight" sands, USGS needs access to appropriate 3-D seismic data to delineate the tight sand bodies, Houseknecht said. There are probably resources in tight sands, even within existing North Slope productions units, but individual sand bodies are probably limited in extent, he said.

### Focus on source rock

So, the agency is focusing on potential oil and gas production direct from source rocks, starting with the Cretaceous Gamma Ray Zone and Hue shale, and the Triassic Shublik formation, two prominent source rock intervals that have generated much oil in the North Slope oil fields, Houseknecht said. Could the source rocks in these intervals be tapped directly for oil production, using hydraulic fracking?


DAVE HOUSEKNECHT

Existing seismic data tied into data from existing wells give geologists a good handle on the geographic extent and thicknesses of the source rock units. But, given the total lack of any track record of unconventional oil and gas production on the North Slope, estimating the rock's production characteristics, the parameters needed to estimate the well drainage cell sizes and well productivity, is one of the biggest challenge in conducting an unconventional resource assessment in northern Alaska, Houseknecht said. Essentially, the geologists have to find analogous rocks from the Lower 48, rocks that have been used for unconventional production and that appear to have somewhat similar characteristics to those on the North Slope, in order to infer the required North Slope production characteristics.

Quite a bit is, however, already known about one key rock property: the distribution of thermal maturity, the measure of the extent to which the rock has been heated to generate oil or natural gas. In general, for example, the thermal maturity is relatively low on the crest of the Barrow arch, a major geologic structure along the Beaufort Sea coast, but increases to the south.

### Gamma ray response

For the Cretaceous sources USGS is using the gamma ray response, a hydrocarbon content indicator, from existing well logs to infer hydrocarbon-rich rock depths and thicknesses at different locations, Houseknecht said. And the good news is that the thickest high-gamma-ray concentrations occur along a trend of thermal maturity appropriate for oil generation, he said.

However, a prevalence of carbonate minerals has distorted the gamma ray responses in the Shublik, causing the USGS geologists to resort to a more complex procedure to locate the likely sweet spots in the Shublik source — using data from the Phoenix well, offshore north of the Colville River Delta, USGS is correlating the thickness of the likely prime hydrocarbon-bearing zone of the Shublik across multiple wells.

And there is evidence from existing well penetrations on the North Slope that the Shublik is fractured and is brittle enough for fracture stimulation,

see **USGS ASSESSMENT** *page 17*

## On the Web

See previous Petroleum News coverage:

"Units may not work for resource plays" in March 13, 2011 issue at http://www.petroleumnews.com/pnads/64464739.shtml

"The ever changing unconventional world" in March 6, 2011 issue at http://www.petroleumnews.com/pnads/672964826.shtml

"Great Bear raises eyebrows" in March 6, 2011 issue at http://www.petroleumnews.com/pnads/312301231.shtml

"Independents: There are ways to stem declining oil flow in line" in Feb. 27, 2011 issue at http://www.petroleumnews.com/pnads/817246686.shtml

"Cook Inlet independents on the move" in Feb. 13, 2011 issue at http://www.petroleumnews.com/pnads/749141112.shtml

"Two different messages at 'Meet Alaska'" in Jan. 30, 2011 issue at http://www.petroleumnews.com/pnads/57206952.shtml

"New oil in 2012?" (Great Bear) in Jan. 30, 2011 issue at http://www.petroleumnews.com/pnads/412876978.shtml

"A source concept" & "Great Bear Petroleum sells $6M in equity" in Nov. 7, 2010 issue at http://www.petroleumnews.com/pnads/900969131.shtml

"Great Bear on slope" in Oct. 31, 2010 issue at http://www.petroleumnews.com/pnads/294242243.shtml

*continued from page 16*

## USGS ASSESSMENT

Houseknecht said.

There's encouragement but quite a bit of uncertainty, he said.

### Cook Inlet basin

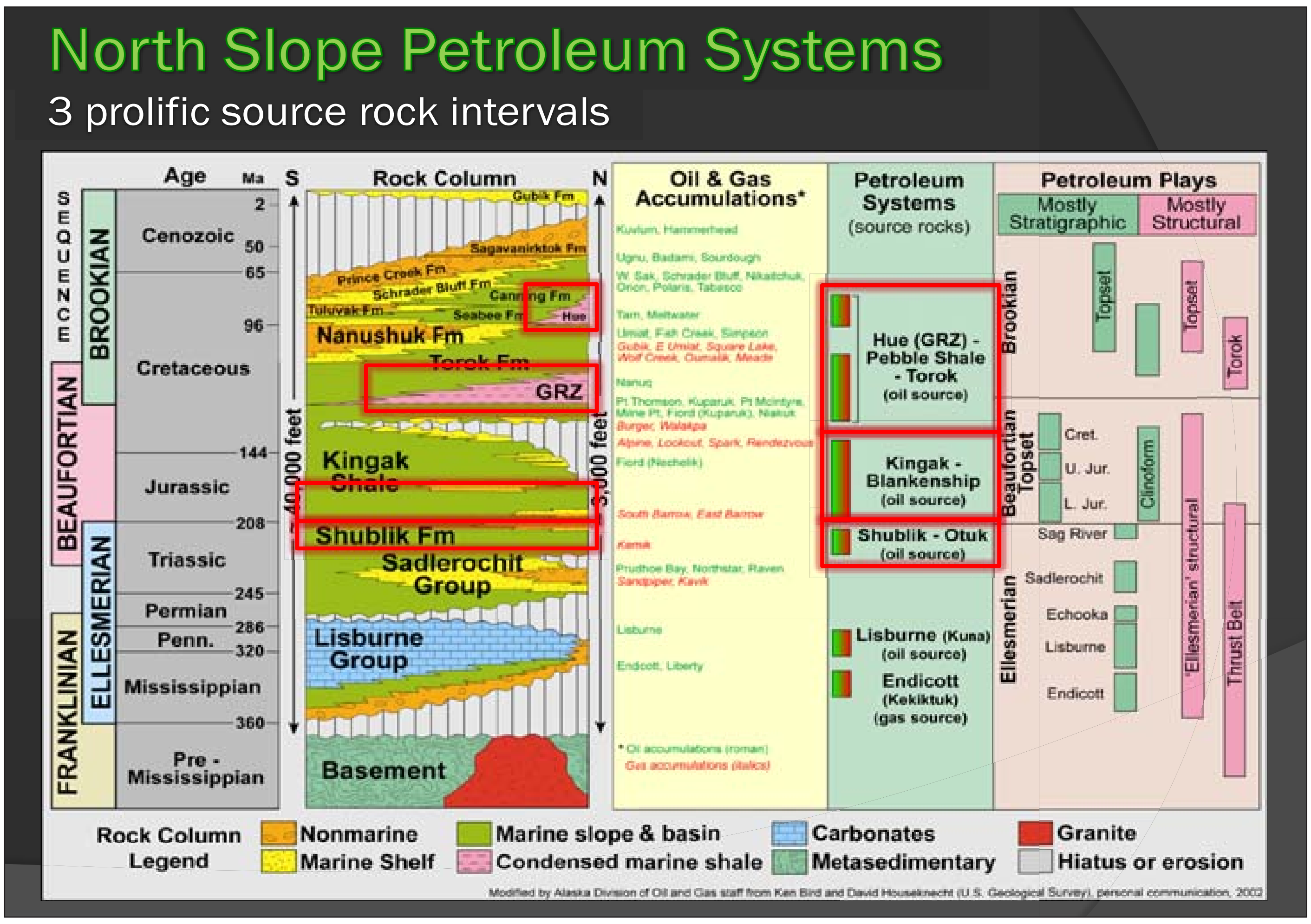
In the Cook Inlet basin, USGS has already committed to an assessment of conventional resources but is now also assessing coalbed methane resources and potential gas production from impermeable or "tight" gas sands. Direct gas production from source rocks, in particular from rocks in the Jurassic Tuxedni group, the main oil source for the Cook Inlet oil fields, is also a possibility, although the paucity of well penetrations into this deeply buried rock unit make it impossible at present to make a quantitative assessment of this play, Houseknecht said.

With massive quantities of Cook Inlet basin coal, much of it in the form of pod-like accumulations rather than continuous coal seams, the potential for coalbed methane production particularly intrigues the USGS geologists and is a significant focus of the Cook Inlet assessment. As with the northern Alaska source rocks, the lack of any production track record in the region drives the need to seek analogous coals elsewhere in order to infer Cook Inlet coal production characteristics. But USGS has a substantial database of coalbed methane production data from North America and the gas production characteristics of many coals tend to be somewhat similar, Houseknecht said.

The USGS geologists have plotted zones where Cook Inlet well data indicate an abundance of thick coal seams, to identify the likely "sweet spots" for coalbed methane production. A large area of territory down the west side of the Cook Inlet seems especially promising. ●

*Contact Alan Bailey at abailey@petroleumnews.com*

PAUL DECKER/ALASKA DNR




## North Alaskan Technical Case

**Comparison: Targeted Alaskan Shales are Superior to the Eagle Ford**

Great Bear Petroleum LLC

*The Eagle Ford shale represents the best analogue to Great Bear's North Alaskan opportunity. Great Bear has not one shale opportunity, but three; all of which are superior to the Eagle Ford.*

| Key Technical Comps | Shublik | Kingak | Hue | Eagle Ford |
|---|---|---|---|---|
| Location | North Alaska | North Alaska | North Alaska | South Texas |
| TOC Average | 4.0 | 5.0 | 4.5 | 3.5 |
| Vitrinite Reflectance | .5 - 2+ | .5 - 2+ | .5 - 2+ | < .5 - 2+ |
| Porosity | < 10%* | < 10%* | < 10%* | < 9% |
| Thickness Range/Average (meters) | 20 - 150/70 | 30 - 50/40 | 50 - 100/100 | 5 - 75/30 |
| Depth (meters) | 2,500-3,000 | 2,500-3,000 | 2,000-2,500 | 3,000-4,500 |

*Notes:*
** Calculated from average Rho log measurements*
*TOC: Total Organic Content (%)*
*Vitrinite Reflectance ($R_o$) is a measure of thermal maturity*

*At the moment the Eagle Ford is the "hottest unconventional oil shale play in the world". We believe that is about to change.*

*Source: Data from Peters, 2006; Masterson, 2001; Jarvie, 2005; EOG 2010*

4



*continued from page 9*

# GREAT BEAR TIMING

acreage Duncan says contains a chunk of the geologic "kitchen" that generated the 100 billion barrels of oil that millions of years ago migrated north into traps along northern Alaska's coast. Those traps include the giant reservoirs of Prudhoe Bay, the largest producing oil field in North America, and Kuparuk, the second largest onshore oil field.

If production begins in 2013 as planned, in a conservatively scaled project of 200 wells a year, Great Bear shows oil production from its acreage alone at 200,000 barrels per day by 2020; 350,000 bpd by 2035; 450,000 bpd by 2041; peaking at 600,000 bpd in 2056, with a sustained long-term production of 450,000 barrels per day out as far as 2074.

*Decker said it appeared Great Bear had "very carefully selected" its acreage position. "They are pretty well positioned, I would say, to pick up the appropriate thermal mature zone for the Triassic and lower Jurassic Kingak." The same, he said, was true for the youngest and shallowest source rock, the Cretaceous-age Hue shale, also called the GRZ, HRZ and Pebble shale.*

That's from exploiting just two of three stacked shale plays in a measured drillout program of 45 years.

When Alaska lawmakers recently asked him if Great Bear could bump the number of wells up to 1,000 a year in order to get a million barrels of oil into the trans-Alaska oil pipeline, Duncan said yes, if he had the support of all the stakeholders in such an accelerated program.

So, why is Duncan certain that his company's acreage holds billions of barrels of recoverable oil?

### A careful, informed selection; not a land grab

The geology of the North Slope is well known and understood, documented by seismic, numerous field studies and well data, Duncan said. So when his company bid on 537,600 acres in last year's North Slope lease sale, it was not making a "blind land grab," a statement confirmed by one of the State of Alaska's leading geologists, Paul Decker, in February testimony before the Alaska Senate Resources Committee, and in an interview with Petroleum News.

Decker said it appeared Great Bear had "very carefully selected" its acreage position.

"They are pretty well positioned, I would say, to pick up the appropriate thermal mature zone for the Triassic and lower Jurassic Kingak."

The same, he said, was true for the youngest and shallowest source rock, the Cretaceous-age Hue shale, also called the GRZ, HRZ and Pebble shale: "Great Bear again is well positioned … for this zone as well."

Indeed, the use of a major basin model that traced the source of the oil in the giant Prudhoe Bay field, and others, was of great help to Duncan.

The report was created by the U.S. Geological Survey. Ken Peters, a former USGS geochemist who worked closely with USGS geologist Ken Bird to create

*see* **GREAT BEAR TIMING** *page 20*

*continued from page 9*

## SOURCE ROCKS

wells most effectively.

### Clues in Texas and N. Dakota

Trying to analyze the source rocks on the North Slope, the most comparable basins are the Eagle Ford shale in Texas and the Bakken shale in North Dakota. On average, North Slope source rocks aren't as organically rich as the Bakken or the best parts of the Eagle Ford, but they are generally thicker. The Shublik rocks appear to be brittle like the Eagle Ford and the Bakken, but typical Shublik-sourced oil is somewhat heavier. The Kingak and GRZ/Hue appear to be less brittle than the Eagle Ford and Bakken, but are known to generate somewhat lighter oil than the Shublik.

"We expect that the Eagle Ford is going to be a pretty good place to look to answer questions that we don't yet know from direct evidence from our own source rock," Decker said.

Does that mean Alaska is as prolific as the Eagle Ford or the Bakken?

Decker said it's still too soon to say, but noted that a U.S. Geological Survey assessment of the unconventional oil and gas resources in Arctic Alaska slated for release next year should shed some light on just how much oil is down there.

"We are very encouraged from what we know right now, but the proof is in the drilling," Decker said.

Currently, only Great Bear Petroleum is looking to explore source rocks, but if it can successfully develop the resource it would likely create a rush on the North Slope. Great Beat President and COO Ed Duncan told lawmakers that he believes his leases alone could contain some 2 billion barrels of oil and 12 trillion cubic feet of natural gas.

### The learning curve ahead

With unconventional oil plays, though, the trick is recovery.

Unlike a conventional reservoir, there are no "dry holes" in source rocks because the rocks are saturated with oil or gas. The question is whether the oil can be recovered.

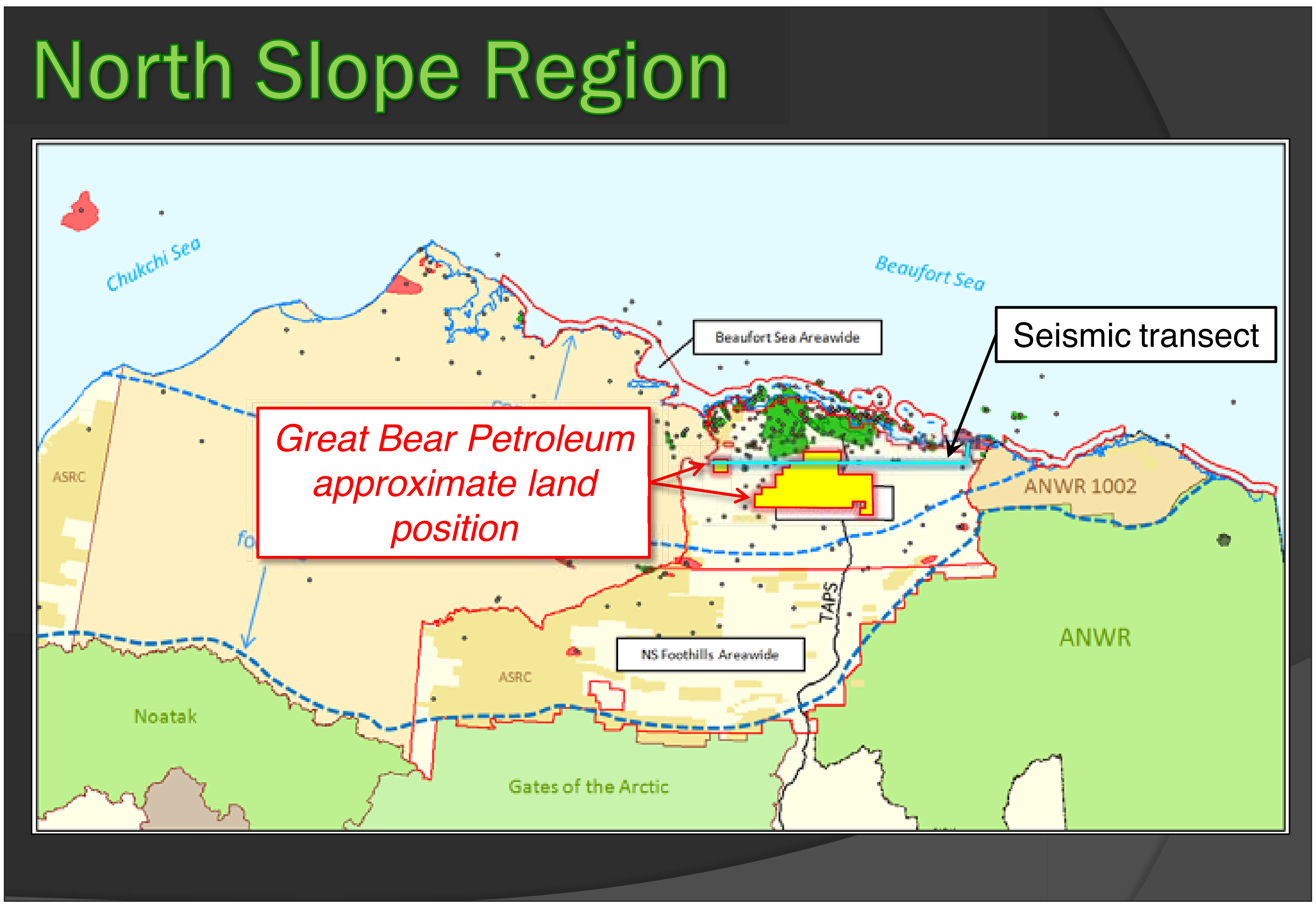
Decker said success on the North Slope would depend on gathering enough good data about the source rocks to support a pilot project. "We are going to need to get on that learning curve and lower the cost of drilling wells. It is partly learning. It's partly just getting enough equipment up there I think. But we need to lower those costs," he said.

A pilot project would help craft an Alaska model for development. Drillers in the Bakken Shale typically drill from five-acre pads spaced every 640 acres. From each pad, one horizontal or multilateral well extends up to two miles in length. Spacing is much tighter in the Eagle Ford, between 125 and 140 acres per well, and would likely be tighter in Alaska, as well, with multiple horizontal wells drilled from each pad. Great Bear plans to use one-acre pads every 120 to160 acres.

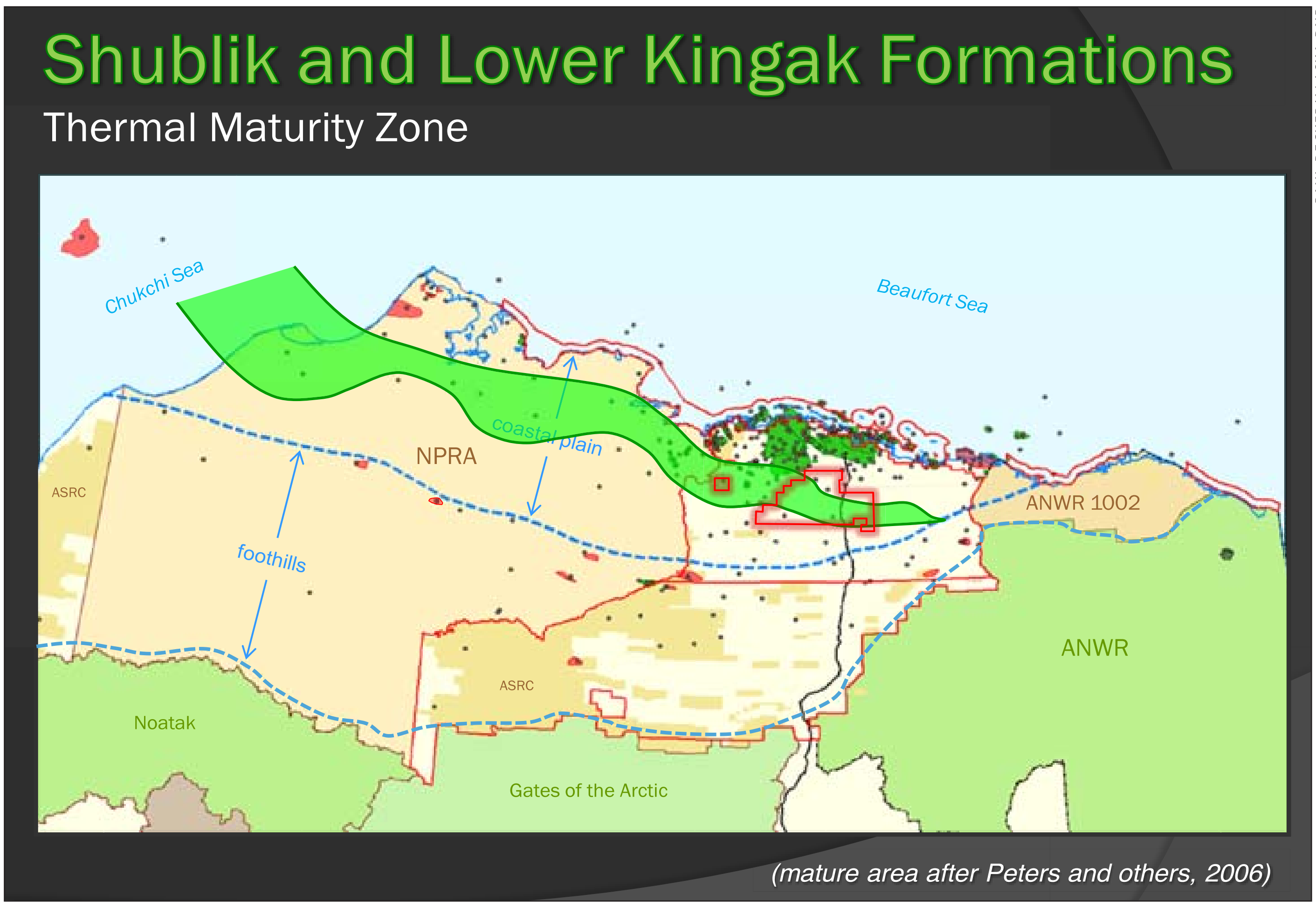
Because source rocks don't yield their resources like conventional resources, drillers must fracture and stimulate the rocks with large amounts of water and sand. Production rates usually decline quickly over the first two years, but decline more slowly over the next decade or more.

Decker said Alaska needs more equipment, more crews, a sufficient water supply, transparent fracturing practices to guarantee that permafrost and drinking water supplies are adequately protected and new all-seasons roads to allow for year-round surface access. ●

*Contact Eric Lidji at ericlidji@mac.com*




PAUL DECKER/ALASKA DNR

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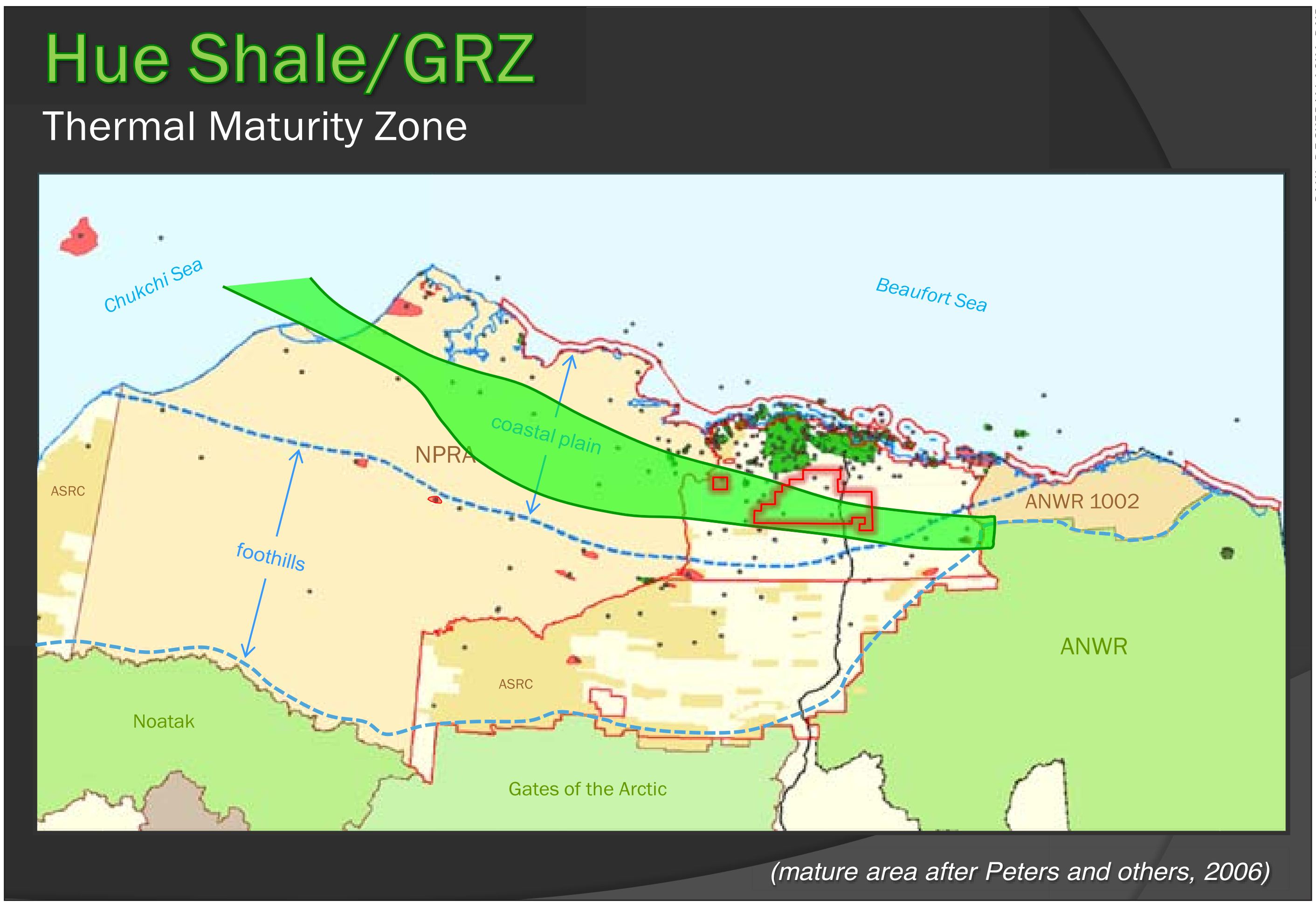



PAUL DECKER/ALASKA DNR

*continued from page 18*

## GREAT BEAR TIMING

the model.

"The model illustrated the oil in reservoirs along the Barrow Arch, including Prudhoe and Kuparuk was generated 75 to 78 percent in the Shublik and Kingak, and the balance was from sources HRZ and Hue shales," Duncan said.

"Based on their model, and on a lot of our work over the year (preceding the October lease sale), the kitchen area where the source rock is mature … is the area we have leased. …

"There are massive amounts of very, very good technical information and studies on this basin. I kept reviewing everything, looking for critical problems, talking to the best geoscientists that I knew of. … We knew where the source rocks were, we knew their thermal maturity. I went over all of it several times alone and with colleagues," Duncan said.

"I am quietly confident … had we not made our move in this lease sale we would have been locked out of it by next. Our timing was fortuitous," Duncan said, echoing the sentiments of the early leaseholders in the Bakken, Eagle Ford and other shale plays in the Lower 48.

*A project supervisor and geologist with the Sohio exploration group, Duncan was in charge of everything on and offshore between the Colville River and the Canadian border, tasked with matching the geology of an area or prospect with advances in technology that might make it economically viable.*

### Matching geology with technology for BP

Considering the job Duncan did for Sohio (now BP) in Alaska, from 1982 to the late 1980s, it's not surprising that Great Bear was first to pick up leases targeting an oil shale play in Alaska's Brookian Foredeep, also known as the Colville basin, which lies north of the Brooks Range.

A project supervisor and geologist with the Sohio exploration group, Duncan was in charge of everything on and offshore between the Colville River and the MacKenzie Delta in Canada, tasked with matching the geology of an area or prospect with advances in technology that might make it economically viable.

So not only was he well versed in the North Slope's petroleum systems, but he was trained to watch for the convergence of technology and geology, which he saw initially with Petrohawk Energy's advances in well design at Eagle Ford, involving everything from increased lateral lengths to less restrictive choke sizes, tighter perforation cluster spacing, increased proppant and the use of new vegetable based fracking gels to overcome concerns about the use of toxic chemicals in hydraulic fracking operations.

### Geology, technology surmountable challenges

Duncan asserts the challenge of producing oil and gas from North Slope source rocks in Great Bear's leases has little to do with the area's geology.

"The challenge is not the geology; it's well understood here. The challenge for the play is: Is it operationally doable on the slope," he said in a recent interview with Petroleum News.

The answer, Duncan said, is yes.

"We got past that issue pretty quickly," he said.

"There's always a chance the rocks just won't perform the way we want them to. We don't expect that. That's way outside our prediction range of outcomes. Also, there's a chance the rocks will perform well beyond what we might imagine from an analog perspective," Duncan said.

He maintains the technology and the geology are a perfect match — or will be as soon as his associates have tweaked their well design.

"We have some technical uncertainties to address — that's one of the reasons we want to do our core holes soon," Duncan said, referring to the holes Great Bear has tentatively scheduled for late fall.

"We need to design our fracs. Our first four planned full production test wells have large R&D research element in them. We'll perfect a method very quickly in the first few wells, then we go into factory drilling, and the costs go down at that point.

"That's the operational model that has been developed in the Lower 48," he said, explaining that he expects the wells to be roughly 9,000 to 11,000 feet deep with 4,000 to 6,000 foot laterals.

"We'll drill down to the source rock and then run the laterals along the source rock strata and using state-of-the-art rock fracturing techniques to cause oil to flow direct from the sources," Duncan said in the interview, repeating much of the same to legislators in his Feb. 26 presentation.

### The Shublik, then the Shublik again

In phases one and two, Great Bear will target the deepest and oldest of the three source rocks, the Triassic-age Shublik formation. In the process the company will drill past the Jurassic-age Kingak shale and the Cretaceous-age Hue shale.

"They are co-located meaning more or less on top of one another," Duncan said. "From a drilling depth perspective we will drill down through the HRZ on the way down to the Kingak, on the way down to the Shublik."

In phase one, the spacing between the wells (about four to a pad) will be 160 acres. In phases two and three, the company will use the same one-acre pads it used for phase one, but it will likely reduce spacing between wells to 80 acres (resulting in about 8 wells per pad), Duncan said..

In phase three, sometime in the first 30 years from when development drilling gets under way — in 2013, if Duncan has his way — Great Bear will target one of the other two source rocks.

"The richest source rock on the North Slope and one of the richest source rocks in North America — in fact, one of the richest source rocks in the world — is the Shublik formation," Duncan told legislators. "Its regional extent, its quality, is extraordinary. And that is our primary target.

"But, again, I can't emphasize enough; we believe that the Kingak and the Hue individually could supply an unconventional resource development on their own. The fact that we have three on the North Slope provides … an extraordinary opportunity. You don't get that in south Texas, you don't get this in the Bakken and you really don't get that in the Marcellus." ●

*Contact Kay Cashman at publisher@petroleumnews.com*

● GOVERNMENT

# Salazar names ocean energy advisory committee members

*Interior's Ocean Energy Safety Advisory Committee to provide guidance on offshore drilling safety, well containment, spill response*

**PETROLEUM NEWS**

Secretary of the Interior Ken Salazar and Bureau of Ocean Energy Management, Regulation and Enforcement Director Michael R. Bromwich on March 11 named the members of the Ocean Energy Safety Advisory Committee.

The permanent advisory body consists of leading scientific, engineering and technical experts who will provide critical guidance on improving offshore drilling safety, well containment, and spill response.

Tom Hunter, former director of the Sandia National Laboratory, a member of the scientific team assembled to assist with the containment and capping of BP's Macondo well, will lead the group as chairman.

"This Safety Committee will help us address some of the most significant issues that will arise as offshore drilling moves forward, said Secretary Salazar. "With Dr. Tom Hunter's leadership, we have brought together some of the most experienced and knowledgeable people in the country to help ensure that safety standards, well containment capabilities, and regulations never again fall behind drilling technology and practices."

"The Safety Committee will play an important role in bringing to bear the expertise, ideas and experience of some of the most knowledgeable people in industry, academia and elsewhere on offshore drilling and safety issues," said BOEMRE Director Bromwich. "It will play a central role in facilitating the exchange of information and ideas, the sharing of best practices and the development of expertise on issues related to offshore energy safety. It will also help us work through some of the more challenging issues we may face in the future, including drilling in frontier areas including the Arctic and ultra deepwater."

## Fifteen members

The committee has 15 members representing federal agencies, the offshore oil and gas industry, academia, national labs and various research organizations.

*The permanent advisory body consists of leading scientific, engineering and technical experts who will provide critical guidance on improving offshore drilling safety, well containment, and spill response.*

Representing the offshore industry are: Charlie Williams, chief scientist for well engineering and production technology, Shell Oil Co.; Paul Siegele, president, Chevron's Energy Technology Co.; Joseph Gebara, senior manager, structural engineer, Technip USA Inc.; and Don Jacobsen, senior vice president operations, Noble Drilling Services Inc.

Members representing the academic community and nongovernmental organizations are: Nancy Leveson, professor, system safety and process safety, Massachusetts Institute of Technology; Richard Sears, senior science and engineering advisor and chief scientist, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling; Tad Patzek, professor and chairman, Department of Petroleum and Geosystems Engineering, University of Texas at Austin; and Lois Epstein, Arctic program director, The Wilderness Society.

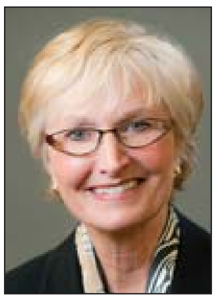
Federal Government designees on the committee are: Walter Cruickshank, deputy director of BOEMRE; Christopher Smith, deputy assistant secretary for oil and natural gas in the Office of Fossil Energy, Department of Energy; Capt. Patrick Little, commanding officer, Marine Safety Center, U.S. Coast Guard; Mathy Stanislaus, assistant administrator for Solid Waste and Emergency Response, Environmental Protection Agency; David Westerholm, director, Office of Response and Restoration, National Oceanic and Atmospheric Administration; and Steve Hickman, a geophysicist with the U.S. Geological Survey. ●

GOVERNMENT

# Ulmer appointed to chair of USARC

President Obama has appointed Fran Ulmer, chancellor of the University of Alaska Anchorage, to a four-year term as chair of the U.S. Arctic Research Commission.

The USARC is an independent federal agency with a mandate to formulate and implement policy on basic and applied Arctic research. Among its other duties, the commission assists federal agencies in establishing a national Arctic research plan, as well as facilitating Arctic research cooperation between the federal government, state government, local governments and international research programs.



FRAN ULMER

## Expanded Arctic emphasis

The commission's current goals for the $400 million U.S. Arctic Research Program include an expanded federal emphasis on Arctic climate and Arctic Ocean research; improved oil spill prevention and response in ice-covered waters; and strengthened research into Arctic human health, indigenous languages and indigenous cultures.

"I am honored to serve as chair of the USARC, particularly during this time of increased attention on the Arctic and the rapid changes being observed in the region," Ulmer said on March 10 in response to her appointment. "I look forward to working with the other commissioners and staff, and the many people in the public and private sectors who are keenly interested in the Arctic."

"Fran brings an intimate knowledge of the Arctic's environment, efforts to promote economic development in the region and the need for the U.S. to be a leader in the Arctic," said Sen. Mark Begich, D-Alaska. "Having her as chair of the commission will help further our nation's efforts to expand our role and harness our potential as an Arctic nation."

—ALAN BAILEY

## GOVERNMENT

### ACMP issues still at play in Juneau

The Alaska Coastal Management Program terminates July 1 unless extended by the Legislature.

The House Resources Committee is in the midst of hearings on a bill from the administration to extend the program for six years; an audit of the program by the Legislative Audit Division recommended a four-year extension; a bill by the Senate Finance Committee would extend the program by one year.

Finance co-Chair Lyman Hoffman, D-Bethel, said March 15 at a Senate Bipartisan Working Group press availability that he doesn't think there is adequate time this year to address coastal zone issues, which is "why I'm supporting a one-year extension."

If the program isn't extended, "I guess we could address starting from scratch and building up a new program next year," Hoffman said, adding that Alaskans, "particularly on the coast, I think unanimously are interested in more participation."

Senate President Gary Stevens, R-Kodiak, agreed that the issue is an important one about which communities are quite concerned and want to be at the table.

"So there's a long ways to go on that issue," Stevens said.

In House Resources, hearings on House Bill 106, the governor's bill to extend the program, are scheduled through March 25, and Resources co-Chair Paul Seaton, R-Homer, said March 16 that a committee substitute had been prepared.

In addition to earlier testimony from Randy Bates, director of the Department of Natural Resources' Division of Coastal and Ocean Management, the committee heard from Legislative Auditor Pat Davidson on March 11 and from Glenn Gray, a consultant representing coastal districts, on March 16.

See coverage of the March 11 and March 16 and upcoming hearings in the March 27 issue of Petroleum News.

—KRISTEN NELSON

● FINANCE & ECONOMY

# Miller CEO hails Alaska energy climate

*Parent company of Cook Inlet Energy announces receipt of $2 million state payment; also recoups $1.5M in tariff deal*

**By WESLEY LOY**
*For Petroleum News*

At least one Alaska oil and gas producer is sounding quite pleased with the state's energy investment climate.

Tennessee-based Miller Energy Resources, which operates in Alaska via subsidiary Cook Inlet Energy LLC, recently announced it had received a tax credit payment of more than $2 million from the state.

The payment "validates Alaska as one of the most favorable development environments for energy today," said Scott Boruff, Miller's chief executive, in a Feb. 10 press release.

*The payment "validates Alaska as one of the most favorable development environments for energy today."*
**—Scott Boruff, CEO, Miller Energy Resources**

The release said that under two laws passed in 2010, Miller is allowed to recover up to 40 percent of its drilling and exploration costs. The laws began as Senate Bill 309 and House Bill 280.

Miller said it earned the $2 million payment as a result of spending "several million dollars" to bring shut-in operations on the west side of Cook Inlet back online.

The payment "represents the combination of two submissions that covered the time period from December 2009 through July 2010 and is the first of several anticipated reimbursements under these new laws, as we are currently preparing our next applications for submission," Boruff said.

He added that planned capital expenditures over the next 12 months "should also yield several million dollars in additional refund payments."

Miller Energy trades as Miller Petroleum Inc. (MILL) on the Nasdaq stock exchange.

The company entered the Alaska scene in late 2009, when it financed Cook Inlet Energy's purchase of an assortment of oil and gas properties previously operated by California-based Pacific Energy Resources Ltd., which liquidated through bankruptcy.

*After a protest to the Regulatory Commission of Alaska, Cook Inlet Energy worked out a tariff settlement with CIPL in late 2010.*

Cook Inlet Energy immediately set about reviving shut-in wells, concentrating first on the West McArthur River oil field.

The new operator soon hit a serious road bump, however, when Cook Inlet Pipe Line Co. sharply hiked its rate for moving oil. CIPL operates a 42-mile pipeline along the western shore of the inlet.

After a protest to the Regulatory Commission of Alaska, Cook Inlet Energy worked out a tariff settlement with CIPL in late 2010.

The settlement included terms — a "true-up" adjustment — providing for the possibility of reimbursement for overpayment in 2010.

On Feb. 18, Miller announced it had received a true-up payment of about $1.5 million in cash from CIPL, with an additional $250,000 to remain in Cook Inlet Energy's account at CIPL for credit against future oil shipments.

"This tariff payment represents the significant cost savings we have realized as a result of last November's settlement," Boruff said. "Those savings will be even more significant as we continue to ramp up our production in Alaska." ●

*Contact Wesley Loy at wloy@petroleumnews.com*

*continued from page 1*

## JACK-UP RIG

Mexico — and the largest blowout preventer ever employed in Cook Inlet.

The blowout preventer and all of its components added an additional $1.5 million to the cost of the program, Davis said at the time, noting it would be installed in Alaska.

He notified AOGCC the rig wouldn't be fully assembled until it arrived in the state, which was acknowledged in a Feb. 25 letter from AOGCC to Davis, deferring inspection until the Spartan 151 was in Alaska.

*Under an agreement with the Alaska Division of Oil and Gas, Escopeta must have the rig bound for Alaska by March 30 and must start drilling its first well by Oct. 31.*

Nonetheless, the preliminary inspection was made by AOGCC on March 9, at Davis' invitation.

"At the time of inspection, Spartan 151 was undergoing modifications for Alaska operations," Commissioners John Norman and Cathy Foerster told Davis in a March 16 letter following the first inspection. "Key well blowout control equipment was missing from the rig. Commission representatives were advised that the missing equipment would be installed on the drilling unit when it arrives in Alaska. As such, a complete inspection of Spartan 151 was not possible."

Under an agreement with the Alaska Division of Oil and Gas, Escopeta must have the rig bound for Alaska by March 30 and must start drilling its first well by Oct. 31.

The company wants to drill Kitchen Lights, an offshore unit in the upper Cook Inlet.

Escopeta is one of two independent oil companies looking to bring a jack-up rig to the Cook Inlet. Buccaneer Alaska is working on a financing plan with the Alaska Industrial Development and Export Authority and should have a deal ready for AIDEA board review soon. ●

*Contact Eric Lidji at ericlidji@mac.com*

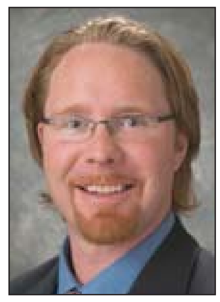
COURTESY ESCOPETA

**Escopeta's Oil's Spartan 151 jack-up was loaded on a heavy lift vessel on March 13 for its trip north to Alaska's Cook Inlet. The stern is pictured above, with the rig sitting on the submerged deck of the vessel.**

Petroleum news

# Oil Patch Bits

## Stoel Rives welcomes Iversen as tax partner


JON IVERSEN

Stoel Rives, a full-service U.S. business law firm, said March 14 that it is pleased to announce Jonathan E. Iversen has joined its Anchorage office as a partner in the Litigation group.

Iversen focuses his practice on litigating tax matters. Before joining Stoel Rives, he served as director of the Tax Division of the Department of Revenue for the State of Alaska from 2007 to 2011. He has deep experience in complex tax matters and has litigated and negotiated settlements of major tax and royalty cases. Iversen served as a core team member in drafting Alaska's oil and gas production tax and property tax laws and regulations. His practice also has an emphasis on oil and gas exploration, development and production matters, including royalties, leasing and unitization.

"Many of our resource industry clients frequently face significant tax disputes with the state. Adding Jon enables us to help them avoid, negotiate or, if necessary, litigate those disputes," said Anchorage office managing partner James E. Torgerson. "Jon has unparalleled insight into the development and structure of the state's current tax regime. We're delighted that he has joined us."

## Solstice names Tauke as production artist


LAURA TAUKE

Solstice Advertising, an Anchorage-based full-service advertising agency, said March 14 that it is pleased to announce Laura Tauke as its new production artist.

As a freelance graphic designer, Tauke's talent has shined with her exhibit and design work at the Alaska SeaLife Center, the Academy of Hair Design and GrassRoots: A Fair Trade Store — just to name a few. Additionally, she co-owned and designed the original Alaska Outlaw Cards, a smashingly successful tourist knick-knack available at retail shops all over the state.

Following her childhood love of logos and brands and her dream to create her own, Tauke studied abroad in Rome, Italy, and received her bachelor of fine arts in graphic design from the College of Design at Iowa State University. Working first in Madison, Wis., before moving to Alaska to seek adventure, she brings an exciting and professional creative edge to the Solstice team, along with an eye for detail that helps clients' projects break through the clutter.

*see* **OIL PATCH BITS** *page 25*

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



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

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## MARKS

and most of Statoil is owned by Norway.

With higher oil prices, there is a greater schism between Alaska and the rest of the world, he said, so the higher the price of oil gets, the less competitive Alaska is, resulting in less oil being produced.

Companies have made billions of dollars in Alaska, Marks said, but the issue isn't how much they can make in Alaska, it's how much more money they could make in other places.

On the issue of ConocoPhillips' Alaska profits compared to the Lower 48, Marks said it's about the difference between oil and gas. In Alaska the company's assets are more than 90 percent oil, compared to about one-third oil in the Lower 48 where the company primarily has natural gas assets and internationally, where the company has about 50-50 oil to gas. ConocoPhillips is relatively more profitable in Alaska because they have relatively more oil, he said, which is much more valuable than gas.

The worldwide competition for investment dollars, Marks said, is oil vs. oil.

### Lots of money

Alaska is making lots of money now, Marks said, so what is the problem?

When ACES passed in 2007 there was a lot of entrenched activity on the North Slope that wasn't going anywhere. But people haven't focused on what's happening to production, he said.

Both the Department of Revenue and the Department of Natural Resources do production forecasts. DNR's forecast has gone out to 2020 since 2000, and while it isn't annual, there have been six forecasts since 2002, Marks said.

Marks compared a 2006 DNR forecast, the last prior to passage of PPT, in which production of almost 900,000 barrels per day was projected for 2010, dropping to some 675,000 bpd by 2020, with a November 2009 forecast, the most recent, which had 2010 production at less than 650,000 bpd and 2020 production dropping below 500,000 bpd.

The difference isn't a matter of fields DNR thought would come online but haven't, Marks said, because more than 80 percent of the oil in DNR's forecast comes from core fields.

Is it all due to ACES? Marks said he didn't think it was all attributable to ACES, but thinks ACES is a major contributor. When DNR estimated 900,000 bpd in 2011 that was based on $50 per barrel oil, he said. With prices much higher than that, you'd think companies would want to produce more oil, but as oil prices go up, Alaska becomes relatively less competitive, Marks said.

He said the drop in DNR's production forecast reflects a drop in investment, because developing individual fault blocks within core fields and developing heavy oil requires capital investment.

### More money better than less

Marks said a basic cornerstone of economic theory is that more money is better than less money, so companies will do what makes them more money and ACES has created a structure that causes people to invest elsewhere.

As for fixing ACES, Marks told legislators he doesn't believe you can fix ACES with more credits: Tax dwarfs credits, he said.

The problem is that taxes are too high, and you can't fix too-high taxes by tinkering with credits — you need to fix the taxes, he said.

And the problem isn't progressivity, but with how progressivity is structured.

Marks noted that while the state has made changes in oil and gas taxes in the past, those changes have always increased taxes. He told legislators this is the first time they've been faced with decreasing taxes, and said he appreciates it's a hand-wringing experience.

He said he's done his best to lay out the rationale for why lowering taxes makes sense — if people can make more money elsewhere they'll go elsewhere.

But he noted that nationally both presidents Kennedy and Reagan proposed tax reductions which passed and the economy rebounded in both cases.

Alaska's resource base is good, he said, so the question is do people have reason to come in and develop that oil vs. oil that they can develop in other places. ●

*Contact Kristen Nelson at knelson@petroleumnews.com*



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## OIL PATCH BITS

### Global Diving & Salvage responds to tsunami damage

COURTESY GLOBAL DIVING & SALVAGE

Global Diving & Salvage Inc. said March 14 that it was engaged by the U.S. Coast Guard to respond to the destruction inflicted to Crescent City, Calif., by the 8-foot tsunami tidal surges generated by the 8.9 magnitude earthquake near Japan. The aftereffects of the tsunami impacted several areas along the West Coast of the United States causing significant damage to marine facilities and vessels unable to escape the onslaught.

Global has been tasked to assist with the removal of fuel, lubricants and other pollution threats from several of the stricken vessels that were sunk or severely damaged during the event. In response Global has mobilized diving and pollution mitigation equipment from their two California offices. Should conditions warrant, Global has the ability to cascade additional resources and personnel from several other company locations.

*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 September.*

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## HEAVY OIL

at the bottom of a well, sucks a mixture of sand and oil to the surface from an unconsolidated sand reservoir, such as the Ugnu. The slurry of sand and oil reaching the wellhead is pumped to a heated separation tank, where the sand sinks out of the oil for removal and disposal.

### Successful test

In 2008 BP successfully tested the CHOPS technique in a single well at S-pad, using standard oilfield equipment to process the produced material. But the new facility represents a considerable scaling up of that initial test, with the installation of custom-built heavy-oil production equipment. That equipment includes a system for minimizing fire risks by heating the facility's separation tanks indirectly using a closed loop of circulating fluid.

BP had hoped to bring the facility into operation in May 2010 but it has taken until now to bring everything together, BP spokesman Steve Rinehart told Petroleum News March 14. The company expects to bring the first CHOPS well on line in mid-April, Rinehart said.

BP has drilled four wells for the testing at the new facility, with two of the wells being horizontal, West said. BP will put processed oil into the flow line for the Milne Point field, with waste sand being trucked to the Prudhoe Bay grind-and-inject facility for disposal.

The purpose of operating the pilot facility is to test the technical viability of heavy oil production, with the eventual aim of assessing the commercial feasibility of a future full-scale plant.

"We're not quite sure what it is going to take commercially to make this work," West said. "What we are focused on right now is proving technical viability."

### Those pesky oil bacteria at work

Heavy oil, such as that found in the Ugnu formation on Alaska's North Slope, is formed when bacteria gobble up the lighter, hydrogen-intense components of regular light oil, leaving behind a residue of the heavier oil components and producing large volumes of methane in the process, Eric West, manager of BP's Alaska renewal team, told a group of state legislators during a presentation on heavy oil on March 10 in Juneau.

The bacteria cannot survive the relatively high temperatures encountered in the deeply buried reservoir rocks of oil fields such as Prudhoe Bay and Kuparuk, so that the oil in these fields has remained relatively light, flowing easily up oil wells and through pipeline systems.

But over time, some oil has spilled from these deep field reservoirs, percolating upwards through the rock strata into relatively shallow rock formations such as the West Sak-Schrader Bluff and the Ugnu, West said. And the shallower the resulting oil pools, the cooler the oil becomes. Conversely, the cooler the oil, the more active and abundant the bacteria become in chomping at the light oil components.

The West Sak-Schrader Bluff formation now hosts what BP refers to as viscous oil, oil with a consistency of maple syrup that can be produced, especially through horizontal wells that access large sections of reservoir. Heavy oil, with the consistency of molasses and unable to flow unaided, is found in the shallower Ugnu formation.

The methane from the bacterial flows upwards to the base of the permafrost, where it combines with water to form methane hydrate, a potential future source of commercial natural gas.

—ALAN BAILEY

### Needs light oil

Heavy oil, with a consistency of molasses, cannot flow unaided down a pipeline for transportation to market. And, although it might be possible to flow the product either by upgrading the oil in a North Slope refinery or by heating the transportation pipeline, BP does not view these options as commercially feasible, thus leaving the dilution of heavy oil production with light oil as the only commercial option for shipping the heavy oil from the Slope.

"Because of that linkage (with light oil), the time to look at heavy oil is now," West said. "And in fact the longer we wait to look at it, the more the light oil declines, and at some point we're going to curtail the amount of heavy oil that we can get off the Slope."

And the prize is huge, given the estimated 20 billion barrels of heavy oil in place on the North Slope. Added to the estimated 10 billion barrels or so in place of viscous oil, the slightly lighter oil that BP and ConocoPhillips already produce from West Sak-Schrader Bluff formation below the Ugnu, a recovery factor of just 10 percent would result in 3 billion barrels of recoverable oil, West said.

In fact, one purpose of operating the new Milne Point test facility is to determine what that recovery factor would be, although BP anticipates recovery percentages somewhere in the low teens using the CHOPS technique, West said.

### Steam inappropriate

Recovery techniques involving the use of steam, in particular a technique called steam assisted gravity drainage, in operation in Canada, have been reported to have achieved recoveries in excess of 50 percent, but these techniques are not appropriate to the reservoir and oil characteristics in the Ugnu reservoir at Milne Point, West said.

And with techniques involving steam it is necessary to evaluate the overall energy balance, determining whether more energy is delivered in the produced oil than is used in producing and injecting the steam required for production.

> *"We're not quite sure what it is going to take commercially to make this work. What we are focused on right now is proving technical viability."*
>
> **—Eric West, manager of BP's Alaska renewal team**

On the other hand the characteristics of the North Slope heavy oil deposits vary east to west in the Ugnu, so that, if heavy oil proves commercial, a variety of different production techniques would likely come into play, with initial production centered on a ramp up of heavy oil drilling around Milne Point S pad — development could involve the drilling of multiple horizontal wells from single, surface well bores, to minimize the surface footprint, West said.

### Significant challenges

But commercial production of heavy oil will face some significant challenges. Heavy oil has less of the light, high-hydrogen components, valued for refining into high-value products such as gasoline, than does light oil, thus giving the heavy oil a lower market value than its lighter cousin. In addition, the production and usage of heavy oil would involve the use of the same value chain of pipelines, oil tankers, refineries and so on as light oil, but with new (and costly) technology bolted on — heavy oil is unlikely to ever be more economic than light oil, West said.

"Heavy oil is not light oil that happens to weigh more," West said. "It is in fact a different commodity. It has different technical challenges."

And although BP's test facility should this year provide some clarity over whether the physics of heavy oil production from the Ugnu works, it will likely take another couple of years, and perhaps another pilot project, to flesh out the production characteristics of the heavy oil resource, he said.

On the other hand, the heavy oil production, at its peak, could add 250,000 barrels per day to overall North Slope production.

"Should we be able to deliver that, it represents a renaissance and rejuvenation of the Alaska North Slope fluids business," West said. "It's a really large resource and we are committed to making it work."

—ALAN BAILEY

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# LNG PLANT

tion, or restarting LNG exports, were some new source of Alaska gas to come online.

At the Energy Task Force meeting, Clark and several other officials from Cook Inlet gas and power businesses discussed some of the issues surrounding the closure of the plant.

### Deliverability back stop

In addition to providing an industrial-scale market for natural gas from the Cook Inlet basin, the LNG plant has acted as a back stop for winter utility gas delivery in Southcentral Alaska: During periods of peak gas demand in severely cold weather ConocoPhillips has diverted gas, otherwise destined for the LNG plant, into the utility gas transmission network. And by providing a market outlet for gas from Cook Inlet wells during the summer, when utility gas demand is low, gas demand from the LNG plant has kept wells in operation year round, thus avoiding the risk of well deterioration, were wells to be temporarily shut-in.

In October 2010 the U.S. Department of Energy approved an application from ConocoPhillips to extend the export license for the plant from March 2011 to March 2013, but the company now says that it is closing the plant because of deteriorating market conditions. In February a Marathon official told The Associated Press that Tokyo Electric Power Co., the company that has been purchasing LNG from the plant for shipment to Japan, had decided not to renew its contract for the purchase of Cook Inlet LNG when that contract expires at the end of March.

Marathon co-owns the LNG plant with ConocoPhillips and is a major Cook Inlet gas producer.

But, regardless of whether the LNG plant were to remain in operation, supplying utility gas from the Cook Inlet basin is going to be difficult, given a continuing decline in peak winter gas delivery since 2006. After a slowing down of that decline since 2007, the decline has accelerated again to an annual rate of about 11 percent this winter, Clark said.

"Next winter there's going to be a challenge in any circumstance, regardless of what the market does and everything else," Clark said.

### Critical time

Carri Lockhart, production manager for Marathon Oil Co. in Alaska, agreed, saying that the winter of 2011-12 will be the critical time for gas deliverability — the rate at which gas can be delivered. Much will hinge on whether the weather remains mild. Supply issues — questions over whether the total annual gas supply volumes will be sufficient to meet the utilities' needs — will start to appear in 2013-14, Lockhart said.

And for several years Southcentral Alaska has been exposed to the risk of a major gas compressor outage somewhere in the gas infrastructure.

"If you have a major compressor going down, when it takes three or four months to secure a new one, that is a huge issue," Lockhart said.

Lockhart said that she is encouraged to see two new operators looking for new Cook Inlet oil and gas. But she also pointed out the commercial challenges for explorers seeking to develop new gas resources in the Cook Inlet basin, given the need to make a return on investment in a gas market that is very small unless there is industrial gas demand.

### Small market

"It's a small market. There's no doubt about it," Lockhart said. "Cook Inlet will always be challenged in that regard of not having a massive market that's fully open, like in the Lower 48."

*Daniel Helmick, manager of regulatory affairs for Municipal Light & Power, said that the utilities would not be surprised if they need to import LNG by 2013 or 2014.*

Lockhart said that, in addition to maintaining its gas storage facility in the Kenai gas field to bolster winter gas deliverability, Marathon has worked on its gas wells to enable the curtailment of gas production in the summer to lower levels than would otherwise be possible without damaging the wells. The company is also installing a bidirectional meter in the Kenai Nikiski pipeline on the Kenai Peninsula, to allow more flexible use of its Kenai storage facility, Lockhart said.

Clark said that, when gas demand slackens in the summer, ConocoPhillips will preferentially maintain production from wells that produce water along with gas, because those wells are most likely to suffer damage if shut-in.

Colleen Starring, president of Enstar Natural Gas Co., said that any damage to wells following well shut-ins could jeopardize Enstar's ability to buy gas at short notice, to meet high winter demand.

"We've been fortunate, let's face it, for the last two years. Mother nature has been extremely kind to Southcentral," Starring said, referencing the relatively mild weather in the past two winters.

### LNG imports

Lee Thibert, senior vice president of Chugach Electric Association, said that the Southcentral utilities are working together on various options to address the tightening gas supply situation, with the conversion of the LNG plant for the import of LNG being one of the possibilities.

"We're all working very diligently, trying to look at all the options … trying to get something decided here, hopefully this summer," Thibert said.

Daniel Helmick, manager of regulatory affairs for Municipal Light & Power, said that the utilities would not be surprised if they need to import LNG by 2013 or 2014.

"That's probably what we'll be working on night and day … for the next several months," Thibert said. "It's not attractive but I think we are in a position where we do have the obligation to serve the customer and make sure the lights are on."

"There's no doubt in my mind that we are going to import fuel, one way or another," said Joe Griffith, general manager of Matanuska Electric Association. "I don't sleep at nights worrying about what we are going to do for fuel in the future. … We can skin the cat but it may cost us a lot more than we would really like to pay."

Clark said that ConocoPhillips has been investigating what would be involved in permitting the conversion of the LNG plant for LNG imports and had not found any major issues. The technical conversion of the plant would probably take about a year, he said.

### New power plant

Thibert talked about the new state-of-the-art, gas-fired power plant that CEA and ML&P are building in south Anchorage. That plant will be 30 percent more efficient than the generating capacity that it replaces, thus saving about 7.5 billion cubic feet of gas annually, Thibert said. The new plant should go into operation by the winter of 2012, by which time CEA should also have available gas that it has stored in the new gas storage facility that Cook Inlet Natural Gas Storage Alaska is building on the Kenai Peninsula.

"The combination of those two (factors) will hopefully take care of the immediate needs," Thibert said.

CEA has firm gas supplies under contract through 2013, is working on acquiring supplies for 2014 and has requirements partially met for 2015 and 2016, he said.

The utility is also addressing issues relating to the transportation of gas from the east side of Cook Inlet to the Beluga power plant on the west side of the inlet by working a project to allow bidirectional flow through the Cook Inlet Gas Gathering System, known as CIGGS, under the waters of the inlet — currently CIGGS only flows gas west to east.

Storage on the east side is of no use to either MEA or ML&P unless it is possible to move gas west under the inlet, Griffith said.

MEA is looking to buy a dual-fuel power plant, potentially to go into operation around September-October 2014, Griffith said, adding that he has been talking to gas independents about purchasing gas.

"I've told them I'd buy every molecule they can produce," Griffith said. ●

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## Accommodating Susitna hydropower

Asked how they would reconcile investments in new gas-fired power generation capacity with the possible future availability of power from a proposed major new hydropower system on the Susitna River, Southcentral electric utility officials told the Anchorage Energy Task Force on March 15 that they support the Susitna hydro proposal and will adjust to the use of Susitna hydropower as necessary. It is a question of allowing room for Susitna power, to accommodate the possibility of that power becoming available, said Lee Thibert, senior vice president of Chugach Electric Association.

Anchorage electric utilities Chugach Electric Association and Municipal Light & Power are already building a new, large gas-fired power plant, planned for start-up in south Anchorage in 2012.

The new gas-fired plant will meet 50 percent of CEA's base-load needs for the foreseeable future, Thibert said. The existing Beluga plant will supply much of utility's remaining power needs, he said.

If the Susitna hydropower plant comes to fruition, power from that plant will replace power from Beluga, with CEA's stable base load being filled by power from Susitna; the new gas-fired power plant would then be used to meet the more variable peaking demand. Essentially the role of the gas-fired plant would change and the plant has been designed to accommodate that change, Thibert said.

By using the relatively inefficient Beluga plant before new hydropower comes on line, CEA will incur relatively high fuel costs, although there is no outstanding capital cost for the aging Beluga plant, Thibert said.

—ALAN BAILEY

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## NORTH TARN

No. 1 by mid-April, but also said it could also end up drilling a sidetrack to the well this winter, depending on results.

"The BRPC Group is optimistically looking forward to see the results of the North Tarn No. 1 exploration well," said Jim Winegarner, vice president of land and external affairs for BRPC. "The North Tarn No. 1 exploration well is the only exploration well being drilled on the North Slope this season; therefore, the BRPC Group holds the title as Alaska's exploration company. We'd rather share that title with many more companies."

While ConocoPhillips plans to drill a gas hydrates exploration well in Prudhoe Bay this year, North Tarn is the only traditional oil exploration well permitted this winter.

BRPC is operating the well on behalf of its parent company, the Kansas-based Alaska Venture Capital Group LLC, as well as three joint venture companies: Brooks Range Development Corp., Ramshorn Investments Inc. and TG World Energy Inc.

The joint venture acquired the North Tarn acreage in January 2010, farming-in six Eni Petroleum leases. Earlier this year, it applied to form the 56,460-acre Southern Miluveach unit over the area. That application is still pending with the Division of Oil and Gas.

### Seven wells in five seasons

North Tarn No. 1 continues the joint venture's march toward being the most active explorer in Alaska over the past five years. Following half a decade of stops and starts after arriving in the state in 1999, AVCG formed an operating arm, gathered acreage, partners and data, and began drilling exploration wells across the North Slope.

The joint venture drilled two wells in 2007 — the North Shore No. 1 well that encountered 70 feet of oil charged Ivishak sandstone and the Sak River No. 1 dry hole.

> *"The North Tarn No. 1 exploration well is the only exploration well being drilled on the North Slope this season, therefore, the BRPC Group holds the title as Alaska's exploration company. We'd rather share that title with many more companies."*
> **—Jim Winegarner, vice president of land and external affairs for BRPC**

In 2008, the joint venture re-entered North Shore No. 1 to test the Ivishak and the Sag River formation, and drilled the Tofkat No. 1 well on acreage along the Colville River, taking 10 oil samples for four sandstone reservoirs and finding six net feet of pay.

In 2009, a lawsuit among partners kept the joint venture from drilling, but the partners resolved it in time to return to the North Slope in 2010 with two wells: Sak River No. 1-A, a sidetrack to the 2007 well, and the North Shore No. 3 well in the Gwydyr Bay area.

In addition to work at its Gwydyr Bay, Tofkat and North Tarn acreage, the joint venture wants to shoot seismic at its Slugger prospect, located south of the Point Thomson unit.

Partner TG World Energy recently announced that it successfully sold its outstanding stock to the Canadian mining company TVI Pacific Inc. The deal allows TG World to raise capital and TVI to expand its resource development operations in the Philippines.

TVI and TG World share a senior executive. ●

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## MAC GAS

That opens the way for negotiations to resume on a federal fiscal framework, the completion of engineering and field work and a start to the process of obtaining about 6,300 permits and authorizations.

The partnership has until the end of 2013 to decide whether to give the final go-ahead and the end of 2015 to start construction, which would likely bring the project onstream in the 2018-20 period, delivering 1.2 billion cubic feet per day to southern markets.

### Imperial looking for balance

The partners are Imperial Oil 34.4 percent, Aboriginal Pipeline Group 33.3 percent, ConocoPhillips Canada 15.7 percent, Shell Canada 11.4 percent and ExxonMobil Canada 5.2 percent.

Imperial is "very pleased" to have the regulatory approval and will now focus on seeking an agreement with the Canadian government on a fiscal framework to "provides an appropriate balance of risk and benefit" for both sides, a spokesman said, while emphasizing that there is a long road ahead.

> *Doug Matthews, a Calgary oil and gas analyst, told the Canadian Broadcasting Corp. earlier this year that the Canadian government has failed to sell the MGP to taxpayers.*

The Northwest Territories government is seeking a fiscal deal that includes loan guarantees and federal money to pay for related infrastructure to ensure the MGP is the springboard to a producing oil and gas basin in the Mackenzie Delta and Beaufort Sea.

TransCanada, the frontrunner to build and operate a gas pipeline from the Mackenzie Delta along the Mackenzie Valley, has argued Arctic gas will be needed to offset the decline in conventional gas in the Western Canada Sedimentary Basin and keep its pipelines operating at capacity.

### APG: Northern gas needed

Bob Reid, president of the APG, said that although the MGP is not economic at current gas prices of around $4 per thousand cubic feet and despite the popular belief that shale gas will serve long-term market requirements, Canada will need northern gas in the latter part of this decade.

He said it is inevitable that gas prices will improve, adding "I'm a firm believer that market forces will prevail."

> *The National Energy Board, following approval from the federal government cabinet, issued a certificate of public convenience and necessity March 9.*

After a long regulatory process, "we are looking forward to moving ahead — finally," he said.

"There's a lot of work to be done and that December 2015 date is going to creep up on us pretty quickly," Reid said.

APG Chairman Fred Carmichael called for support to put pressure on the Canadian government to follow the U.S. government lead and "provide a loan guarantee that will make this project happen."

He said the APG will need to borrow up to C$6 billion to secure its equity stake in the pipeline and a federal loan guarantee would allow the APG to obtain that money "at the lowest possible interest rate."

### Analyst sees little support

Doug Matthews, a Calgary oil and gas analyst, told the Canadian Broadcasting Corp. earlier this year that the Canadian government has failed to sell the MGP to taxpayers.

"I think there's very little support, certainly within the federal government, for significant financial injections into this project. And that's just too bad," he said. "You're hard pressed to think back to a cabinet minister really going public with strong support for the MGP."

Despite recent signs of renewed support for the MGP, FirstEnergy Capital analyst Steven Paget said the outlook for the North American gas market is more crucial than the regulatory formalities.

He said shale gas projects, which are much closer to existing infrastructure and major population centers than the MGP, are likely to proceed first.

Paget said the MGP would need gas prices of $6-$8 per thousand cubic feet to proceed and that is not likely before at least 2015 and, according to Canadian Natural Resources, possibly as late as 2018.

Alberta Energy Minister Ron Liepert said the current price of gas does not justify either the Mackenzie or Alaska pipelines.

"There are challenges to overcome and they are economic rather than environmental or land concern issues," he said.

Joe Marushack, Canadian president for ConocoPhillips, said earlier in March the MGP is a "pretty tough project" given where gas prices stand.

—GARY PARK

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