A 6-month window

Commission, gas and electric utilities need to be ready for open season

By KRISTEN NELSON
Petroleum News

Alaska is well positioned to take gas off in-state under an initial open season for a North Slope natural gas pipeline project. But if for any reason potential in-state users don’t take capacity on the main line in that initial open season, they are not well positioned to ask to take gas off later.


“We have an outstanding position during the initial phase,” he said. “If we speak up, then it’s very clear” that in the initial open season, requirements for in-state Alaska gas have to be accommodated both in pipeline design and in tariff structuring.

“It is also clear that if we miss the window and we come back, say, a year later” requesting to take off 100 million cubic feet a day in Delta Junction, “they’d say … sorry, but you have to pay the full fare to Chicago because you’re asking me to let gas off early and I have … financed it on the basis of all the gas going to Chicago.”

That initial open season window is six months.

GOM energy act passes

8.3M exploration acres opened in eastern Gulf of Mexico; industry reaction mixed

By RAY TYSON
For Petroleum News

The Republican-led Congress, before turning over the reins to the Democrats, passed 11th hour legislation opening an additional 8.3 million acres in the eastern Gulf of Mexico to oil and gas exploration.

The drilling measure was viewed as a political compromise, wrapped in a broad tax and trade package that the U.S. Senate approved Dec. 9 by a 79-9 vote, just hours after the House of Representatives okayed the legislation.

Earlier versions of the bill pushed by Republicans would have opened offshore areas of the U.S. West and East coasts to exploration drilling. But with the clock ticking down to adjournment of the 109th Congress and no clear consensus, both houses settled for passage of the Gulf of Mexico Energy Security Act of 2006.

Democrats, who mustered enough seats in the November election to take control of Congress next year, largely supported the offshore bill. However, they also are expected to try to repeal oil and gas subsidies.

Gulf Coast states get more royalties

The final bill passed by both houses also provides the Gulf Coast states of Texas, Louisiana, Mississippi and Alabama with a 37.5 percent share of federal royalties.

LNG threatens costly gas

EIA expects liquefied natural gas imports to Lower 48 will climb to 4.5 tcf by 2030

By GARY PARK
For Petroleum News

Not only might imports of liquefied natural gas to North America offset the anticipated loss of Canadian supplies over the next decade, they could also spell trouble for the more expensive plays that are starting to dominate the gas sector in Canada.

In its latest annual energy outlook the U.S. Energy Information Administration said shipments from Canada will start to slow at the midpoint of its forecast covering 2005-2030. The report predicts that gas from Canada will hold steady between 2.3 trillion cubic feet and 3 tcf over 2003-2015, then begin a steady descent to 900 billion cubic feet.

The EIA said the decline will stem from depletion clock ticking down to adjournment of the 109th Congress and no clear consensus, both houses settled for passage of the Gulf of Mexico Energy Security Act of 2006.

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The EIA said the decline will stem from depletion

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11 U.S. approves first FPSO in Gulf: Petrosbas plans to use floating, production, storage and offloading system in ultra deep water

Harold Heineze

British Columbia bears brunt of Devon cutbacks

Unhappy about the high-cost operating environment in Canada, Devon Energy is reining in its 2007 spending north of the 49th parallel — and it is not alone, much to the concern of British Columbia’s booming natural gas business.

Although Devon has no plans to pull out of Canada, company President John Richels, former head of Devon’s Canadian subsidiary, said the budget trimming is a necessary part of fiscal discipline.

Speaking to analysts in November, he said:

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#### Alaska Rig Status

**North Slope - Onshore**

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<thead>
<tr>
<th>Rig Owner/Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
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<tbody>
<tr>
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<td>Dreco 1250 UE 14 (SCR/TD)</td>
<td>Milne Point MP-98A</td>
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<td>Sky Top Brewster NE-1-2 15 (SCR/TD)</td>
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<td>ConocoPhillips</td>
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<td>DMX 2000 141 (SCR/TD)</td>
<td>Kuparuk 1-103</td>
<td>ConocoPhillips</td>
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<td>TSM 7000 Arctic Fox #1</td>
<td>Stacked in Yard</td>
<td>Pioneer Natural Resources</td>
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<tr>
<td></td>
<td>Arctic Wolf #2</td>
<td>Stacked in Yard</td>
<td>FEX</td>
</tr>
<tr>
<td></td>
<td>Kuukpik 5</td>
<td>Mobilizing to 2P pad, for eventual mobilization to Noatak</td>
<td>ConocoPhillips</td>
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<tr>
<td></td>
<td>Nabors Alaska Drilling</td>
<td>Trans-arctic rig</td>
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<td></td>
<td>Oilwell 700 E 2-ES DS 15-12B</td>
<td>GPB</td>
<td>BP</td>
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<td>S-31A</td>
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<td>Dreco 1000 UE 9-ES (SCR/TD)</td>
<td>V-122</td>
<td>BP</td>
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<tr>
<td></td>
<td>Oilwell 2000 Hercules</td>
<td>Stacked at Cape Simpson</td>
<td>FEX</td>
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<td></td>
<td>Oilwell 2000 Hercules</td>
<td>Under contract for drilling at Gwydyr Bay</td>
<td>Brooks Range Petroleum</td>
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<td>Oilwell 2000 17-E (SCR/TD)</td>
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<td>Emisco Electro-hoist -2</td>
<td>Stacked, Deadhorse</td>
<td>Available</td>
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<td></td>
<td>DMX 1000 19-E (SCR)</td>
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<td>Oilwell 2000 245-E</td>
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<td>Nordic Catala Services</td>
<td>Superior 700 UE 1 (SCR/CTD)</td>
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<td>Chevron</td>
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<td>Nabors Alaska Drilling</td>
<td>Oilwell 2000 33-E Northstar NS-14</td>
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<td>Franks 300 Sts. Explorer III AWS 1</td>
<td>Stacked at Nikiski</td>
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<td>Marathon Oil Co. (Inlet Drilling Alaska labor contractor)</td>
<td>Taylor Glacier 1 R rig maintenance</td>
<td>Marathon</td>
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<td>National 110 UE 160 (SCR)</td>
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<td></td>
<td>Franks 29</td>
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<td>Available</td>
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<td></td>
<td>EICO 2100 E</td>
<td>429R (SCR)</td>
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<td></td>
<td>Rigmaster 850</td>
<td>129</td>
<td>Swanson River SRU 41-05</td>
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</tbody>
</table>

#### Cook Inlet Basin – Onshore

<table>
<thead>
<tr>
<th>Rig Owner/Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
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<tbody>
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<td>XTO Energy</td>
<td>National 110 A (TD)</td>
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<td>XTO</td>
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<tr>
<td></td>
<td>National 110 C (TD)</td>
<td>Idle</td>
<td>XTO</td>
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<tr>
<td></td>
<td>Cudd Pressure Control</td>
<td>Cudd 3400 Jack Unit</td>
<td>Workover Ahtna #1-19</td>
</tr>
</tbody>
</table>

#### Mackenzie Rig Status

**Canadian Beaufort Sea**

- **Soutankers (AKITA Equtak labor contract)**
  - SDC: CANMAR Island Rig #2 SDC
  - Set down at Roland Bay
  - Devon ARL Corp.

#### Mackenzie Delta-Onshore

- **AKITA Equtak**
  - Dreco 1250 UE 62 (SCR/TD) Stacked in Tuktoyaktuk, NT
  - EnCana

#### Yukon Territories Rig Status

**Northwest Territories**

- **Energent Resources Socc Corp.**
  - Jackknife Double 55 Racked in Ft. Nelson

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*The Alaska - Mackenzie Rig Report is sponsored by:*

Baker Hughes North America rotary rig counts*

<table>
<thead>
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<th></th>
<th>Nov. 10</th>
<th>Nov. 3</th>
<th>Year Ago</th>
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<td>1,693</td>
<td>1,739</td>
<td>1,479</td>
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<td>Canada</td>
<td>446</td>
<td>376</td>
<td>569</td>
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<tr>
<td>Gulf</td>
<td>82</td>
<td>87</td>
<td>77</td>
</tr>
</tbody>
</table>

**Highest/Lowest**

- US/Highest: 4530 December 1981
- US/Lowest: 488 April 1999
- Canada/Highest: 599 January 2000
- Canada/Lowest: 25 April 1992

*Issued by Baker Hughes since 1944*
Produced water: could it be a valuable resource?

By ALAN BAILEY
Petroleum News

P roduced water — the underground water that comes to surface as part of oil and natural gas production — has traditionally enjoyed few uses other than reinjection into oil reservoirs to flush out more oil. But could the water provide additional value? On Dec. 5 the U.S. House of Representatives passed the More Water for More Energy Act of 2006, legislation that aims to push value-adding uses for produced water. The act directs the Secretary of the Interior, acting through the commissioner of Reclamation and the director of the U.S. Geological Survey, to conduct a study into making more use of the water. The study will identify the obstacles to increasing the use of produced water for irrigation and other purposes and will establish actions to overcome those obstacles. The act also directs the secretary of the Interior to award grants to assist in the development of facilities that demonstrate how the use of produced water can increase.

IOGCC has done national research

The Interstate Oil and Gas Compact Commission, an agency that promotes the efficient recovery and the conservation, the recycling and the effective recovery of oil and natural gas, has conducted a national research program into the uses of produced water. The U.S. Department of Energy funded the research, while representatives from ALL Consulting, the Montana Board of Oil and Gas Conservation, the Wyoming Oil and Gas Conservation Commission, the Alaska Oil and Gas Conservation Commission, the Oklahoma Corporation Commission, the Kansas Corporation Commission, Citizens for Resource Development and the oil and natural gas industry assisted with the research.

Among the research findings was a determination that U.S. oil and natural gas operations yield approximately 14 billion barrels of water every year. The salinity of some of this water is too high for crop irrigation but large quantities of produced water could be used in applications such as power generation or enhanced oil recovery. In November IOGCC used the research results in expert testimony in support of the More Water for More Energy bill. The commission believes that more use could be made of produced water.

“Produced water as a result of oil and gas production represents a valuable natural resource to this country, especially in the arid western United States and in areas experiencing prolonged drought,” said Christine Hansen, IOGCC executive director. “The IOGCC is pleased that this bill recognizes the benefits of this resource so it will not be wasted.”

The report from the IOGCC research is available at http://www.iogcc.state.ok.us/news_pubs.aspx.

FINANCE & ECONOMY

Paramount sets Mackenzie spin-off terms

Shareholders of Paramount Resources will get a front-line opportunity to participate in northern oil and gas exploration when the Canadian independent spins off its Northwest Territories assets.

Under a plan of arrangement announced Dec. 11, the investors will get one share of the new Arctic company and five warrants for every 25 Paramount shares they hold.

The deal will be voted on by the shareholders on Jan. 11, with the spinout expected to be in place the next day.

Paramount will initially own 87 percent of the so-called Newco. In once in place, the publicly traded company will own rights under a farm-in agreement Paramount negotiated in September with Chevron Canada and BP Canada Energy covering about 1.019 million gross acres on the Mackenzie Delta and oil and gas properties in the Colville Lake area of the Mackenzie Delta covering 1.483 million gross acres.

Company has drilling plans

When it first announced the plan, Paramount said the new company would drill on the Delta lands, where Chevron and BP have recorded some success.

Meanwhile, Paramount will retain its existing producing assets and its undeveloped acreage, which will be run by the existing management team.

The chief executive officer of Newco will be Clayton Riddell, Paramount’s president and chief executive officer.

The proceeds from the exercise of the short and longer term warrants will be used to fund programs under the Delta farm-in, which are expected to be about $130 million to the end of the 2007-2008 winter drilling season.

—GARY PARK
By GARY PARK
For Petroleum News

Talisman Energy has completed a large part of its planned exit from the oil sands, but an extensive list of leases is still up for grabs.

As expected, Canadian Oil Sands Trust landed Talisman’s 2.25 percent stake in the Syncrude Canada consortium for C$475 million, while Suncor Energy bought Talisman’s 2 percent gross overriding royalty on Suncor’s Lease 23 near its Steepbank mine for C$107.5 million.

The Syncrude deal consisted of C$237.5 million in cash and 8.19 million units of COST, raising its dominant stake in Syncrude to 100 percent.

Talisman’s 2 percent gross overriding royalty on Suncor’s Lease 2006, collecting about C$800 million in additional production revenues, was sold to EnCana for C$237.5 million.

Talisman’s share of production was rated at 4,375 barrels per day, although it has averaged only 3,400 bpd this year.

In placing its Athabasca assets on the block to clear the way for a concentrated push on its new natural gas play in the Foothills region of Alberta, Talisman attracted interest from more than 50 companies.

It hopes to have other sales concluded by the end of 2006, collecting about C$800 million in additional proceeds. They involve a 100 percent working interest in Lease 19, a 6,800 acre lease immediately south of Suncor’s Steepbank mine and a 75 percent working interest in Lease 50 covering 21,800 acres north of the OPTI Canada-Nexen joint venture at Long Lake.

Koch, Petro-Canada also seeking buyers

Koch Exploration and Petro-Canada are also seeking buyers for major leases.

Koch is offering 374,000 net acres in the Athabasca region consisting of an estimated 23 billion barrels of bitumen resource and likely to fetch as much as C$750 million.

Petro-Canada is selling various interests in five in-situ properties — Chard, Stony Mountain, Liege, Thornbury and Liptak — estimated to contain 1.7 billion barrels of bitumen resource and likely to fetch as much as C$750 million.

Industry observers are counting on strong international interest in the assets, especially from Korean interests after Korea National Oil Corp. bought leases from Newmont Mining in July, but Norwegian’s Statoil, Norsk Hydro, Japan Shell and Korea National Oil Corp. have competed for lease interests.

Other possible contenders include Nexen-OPIT, EnCana, Devon Canada, North American Oil Sands, MEG Energy (which has China National Offshore Oil Corp. as a 16.69 percent partner in a project) and ConocoPhillips Oil and Gas.

Athabasca project partners Chevron and Western Oil Sands are also viewed as active acquirers.

November sale nets C$78.2 million

The hunger for oil sands property shows no signs of diminishing at Alberta government sales, with bidders paying C$37.2 million to take 2,530 acres in the West Block.

Scott Land & Lease, acting for an unidentified client, paid C$37 million for rights to 27,800 acres, while Saskatoon Assets paid C$28 million for a connecting parcel.

The parcels are northwest and northeast of the Firebag West and Muskeg area interests held by Value Creation and Shell Canada.

Shell combined with RSX Energy to bid C$1.19 million for 1,265 acres in the same area where it paid C$6.2 million for 2,530 acres in July.

So far this year, oil sands rights have claimed more than half the C$32.9 billion the government has collected at its bi-monthly auctions.

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PPT regulations out for comment, hearing set

The Alaska Department of Revenue said Nov. 13 that it has proposed regulations for the new oil and gas production tax passed by the Legislature in August out for review, and has scheduled a hearing in January to take comments on the regulations.

The department said many of the proposed regulations changes would apply retroactively to April 1, 2006, although in some cases the changes are proposed to apply retroactively to March 1, 2007, in the event the changes take effect after that date.

The proposed regulation language is available online at www.legis.state.ak.us/folhome.htm. Select “The Alaska Administrative Code,” “Title 15 Revenue” and then “Chapter 55 Oil and Gas Properties Production Tax.”

The department is seeking public comment on the proposed regulations.

Written comments may be submitted to Gary Rogers, Tax Division, Department of Revenue, State of Alaska, 550 W. 7th Ave., Ste. 500, Anchorage, AK 99501, or by email to gary_rogers@revenue.state.ak.us or by facsimile to: (907) 269-6644, attention Gary Rogers, Tax Division. Rogers is also the contact for a copy of the proposed regulations.

The department said comments must be received by 5 p.m. Jan. 17, 2007, and noted that both written and oral comments received are public records and are subject to public inspection.

The department will also take oral or written comments at a public hearing Jan. 11-12 in Room 240, 550 W. 7th Ave., Anchorage, Alaska. The hearing will be held on both days from 9 a.m. to 12 p.m. and the department said the hearing might be extended to accommodate those present before 12:00 p.m. who have not had an opportunity to comment.

Comments in the public hearing may be made by phone. The number is (907) 315-6338. When prompted for the code enter 1014#.

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Over the past 70 years we’ve gone from a small float-plane operation in and around Anchorage to servicing more than 80 destinations across the United States, Canada and Mexico. And although where we fly and what we fly may have changed since 1932, the reason we fly hasn’t changed a bit. We fly for you.

COMMITTED TO CARGO

Alaska Air Cargo
alaskacargo.com
Anadarko, Devon score oil at Mission Deep

Deepwater partners Anadarko Petroleum and Devon Energy said they made an oil discovery on their Mission Deep prospect in the Gulf of Mexico, adding that the exploration well encountered more than 240 feet of net pay in the primary middle Miocene target.

Located on Green Canyon block 955, the discovery well was drilled to a depth of about 25,000 feet, including 7,300 feet of water. Future plans include deepening the well to a secondary Lower Tertiary objective and drilling a sidetrack well to further delineate the extent of the reservoir, Mission Deep operator Anadarko said Dec. 11.

Mission Deep is Anadarko’s ninth discovery out of a dozen tests so far this year in the deepwater Gulf of Mexico, following up on last year’s deepwater exploration program in which the company was successful in five of nine attempts.

Anadarko has an inventory of about 150 prospects and leads in the U.S. Gulf, representing an estimated 13 billion to 18 billion barrels of “gross un-risked” resource potential, said Bob Daniels, Anadarko’s senior vice president of worldwide exploration.

“Anadarko plans to drill 10 to 15 exploration tests over the next two years to evaluate this potential within our focused position in the Miocene and emerging Lower Tertiary plays,” he said.

Devon also successful in Walker Ridge

Anadarko and Devon are 50-50 partners in the Mission Deep prospect. Devon also has had success in the highly acclaimed Lower Tertiary play with its Cascade, St. Malo and Jack discoveries in Walker Ridge. Devon and Anadarko own a share of another Lower Tertiary discovery called Kaskida, located in Keathley Canyon and operated by BP.

“With 15 additional prospects in our Miocene inventory and nearly 20 Lower Tertiary prospects, we are very optimistic about continued success from our Gulf exploration program in 2007 and beyond,” Stephen Hadden, Devon’s senior vice president of exploration and production, said, adding that Devon’s deepwater Gulf prospect inventory represents up to 7 billion barrels of resource potential.

Devon said it is paying 100 percent of the cost of the Mission Deep well pursuant to the terms of a joint venture agreement entered into with Kerr-McGee Corp. prior to inventory represents up to 7 billion barrels of resource potential. But even before the federal government announced the tax rules that would govern the trusts in the future as well as its failure to indicate whether there would be any retroactive application of the rules to transactions that were in the works before the Oct. 31 announcement that trusts would be taxed at the same rate as conventional companies.

“We had sought clarity and hadn’t received it,” he said.

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“We had sought clarity and hadn’t received it,” he said.

Guidance promised before Christmas

The best Finance Minister Jim Flaherty has promised is that the guid- ance for the transition period to 2011 will be released before Christmas, although legislation is not expected to be tabled until early 2007.

The only sign of the government’s thinking was a “comfort” letter from Flaherty’s department that encouraged Pengrowth Energy Trust to stick with its planned C$1.04 billion purchase of Alberta oil and gas assets from ConocoPhillips.

But the frustration in the trust world was expressed Dec. 6 by George Kesteven, president of the Canadian Association of Income Funds, who said that even if the government provides the details of the tax changes before Christmas it will likely take much longer to grasp the consequences.

“Part of the problem we have right now is there is no road map from the government over the four-year time frame,” he told the Calgary Herald’s editorial board.

“In addition to the lack of clarity around ‘undue expansion’ and growth no one has told us what we’ve supposed to look like in four years. (Does the government) want us to convert to corporation?’’ he asked.

In a meeting with Flaherty earlier in December, the association representing 250 trusts covering a wide business spectrum, with about one-fifth from the energy sector, asked the minister to allow existing trusts to continue as they do under the legislation.

Failing that, the association requested a 10-year transition period.

Kesteven said the market is in a state of “suspended animation until we get clarity,” adding that the “bad policy” of Oct. 31 is continuing to inflict damage.

ALTERNATIVE ENERGY

Alaska tidal energy conference scheduled

The Alaska Energy Authority is holding Alaska’s first tidal energy confer- ence in the Ted Ferry Conference Center in Ketchikan on Jan. 23 and 24. A vari- ety of experts will give presentations and there are over 300 attendees.

AEA is investigating alternative energy sources, including tidal power, as replacements for diesel fuel in some areas of Alaska.

Conference presentations will include:

– A tidal energy tax review;
– A report on Verdant Power’s New York city East River environmental study;
– The tidal energy resources of selected southeast Alaska sites;
– Tidal energy devices nearing commercialization; and
– Opportunities and obstacles to project development.

Stevens said tidal energy projects would be presented by Roger Bedard, Electric Power Research Institute ocean energy project manager and co-author of EPRl’s international studies and reports on wave and tidal energy; and Troy Taylor, co-founder and president of Verdant Power, a company that specializes in generating electricity from natu- ral underwater currents.

In addition to AEA, Ketchikan Public Utilities; Alaska Electric Power and Light Company; Alaska Power and Telephone; and the Denali commission are sponsoring the conference.

For more information or to register contact Kim Hendricks at KM1HH@city.ketchikan.ak.us or (907) 228-5446.
Pioneer Natural Resources Alaska has completed an application to expand its North Slope Oooguruk unit, which now includes 12 State of Alaska oil and gas leases, with an additional seven state leases. The Alaska Department of Natural Resources said Nov. 30 that the expansion would increase the unit’s size by 150 percent, from 20,394 acres to 50,883 acres.

Pioneer applied to have state leases ADL 355036, 355037, 355038, 355039, 355040, 359960 and 379301 added to the unit last year; the Alaska Department of Natural Resources’ Division of Oil and Gas asked for more information and found the application complete in late November. The application is now out for 30-day public comment; the division then has 60 days to issue a decision.

Oooguruk is offshore the North Slope and adjacent to the Kuparuk River unit on the east.

Six of the seven additional leases are in a block on the southwest of the existing unit, which was approved in 2003; the seventh lease is on the eastern edge of the unit, between existing unit leases.

Pioneer did not control these seven leases when the unit was formed. It subsequently acquired four of the leases from ConocoPhillips and the other three from Anadarko Petroleum.

Company has drilled three wells

Pioneer originally partnered with Armstrong Alaska, which subsequently sold its Alaska interests to ENI Petroleum Exploration; unit leases are now held 70 percent by Pioneer and 30 percent by ENI.

Armstrong submitted a plan of operation for Oooguruk in July 2002; in December of that year, Armstrong assigned 70 percent of its working interest in nine leases to Pioneer, which became operator and began an exploration drilling program targeting the Kuparuk C sands.

Pioneer submitted an application for the Oooguruk unit in January 2003, which the division approved in July 2003. Pioneer spud the Ivik 1 well in February 2003 and went on to drill the Oooguruk 1 and the Natchik 1.

DNR approved royalty modification for nine leases in February 2006, the same month in which Pioneer approved unit development.

Four of the leases were acquired in 1983 on a net profit share basis, with 10-year primary terms of a fixed 12.5 percent royalty rate and 30 percent net profit share for the state. These four leases were committed to the Kukpik unit, which terminated in 2001. Prior to lease expiration, a well was drilled on each lease and the wells were certified capable of producing in paying quantities, extending the leases, primary terms indefinitely.

The royalty modification requested a 5 percent royalty rate and a 30 percent net profit share to the state for the NPS leases and a modification from 16.6667 percent to 5 percent on five other leases.

DNR implemented royalty relief as follows: a 5 percent royalty rate for production from delineated pools until NPS payments first become due to the state from ADL 355036, which occurs when costs of the development are paid off.

In the first month following the month when NPS payments first become due, a four-year royalty modification phase-out begins for all nine leases subject to the royalty modification, with a 1.875 percent increase in the royalty rate until that rate reaches 12.5 percent for the four leases with a 12.5 percent royalty. NPS remains at 30 percent for those leases.

At the beginning of the fourth 12-month period after NPS payments become due from ADL 355036, the royalty rate will immediately be restored to 16.6667 percent for the non-NPS leases.

The decision also required that the project be sanctioned by Dec. 31, 2007; sanction occurred in 2005, with gravel island construction the winter of 2005-06, production modules going in in 2007, as well as the subssea pipeline. Development drilling is expected to start in 2007, with first production in 2008.

Area of known discoveries

The state said there are six wells certified capable of production in paying quantities within the proposed expansion area — five on net profit share leases for which Pioneer received royalty relief — and two other certified wells in the vicinity of the unit.

The eight wells certified by the state are: Exxon Thetis Island 1, in the north-east part of the unit; ARCO Kalubik 1; and four Colville Delta wells (Texaco Colville 1, 1A, 2 and 3) that lie on the four net profit share leases. The two other certified wells, outside and to the west of the unit, are the Kuukpik 3 (approximately two and one half miles) and the Amerada Hess Corp. Colville 25-13-6 (approximately a quarter of a mile).

Pioneer Natural Resources President and COO Timothy Dove said in a November analysts’ call that the company is looking at adjacent opportunities to possibly tie into Oooguruk.

He said there are “known reserves in and around Oooguruk that we’re now evaluating for potential tie-ins as we get closer to actual production. In fact we know that there’s a known resource about two to three miles away that’s 20 million to 30 million barrels, which has several wells already having penetrated it.”

“If you’re standing on Pioneer’s island and look around in a two- to three-mile radius you’ll see an area that was initially drilled mainly by Texaco and ARCO,” Bill Van Dyke of the Alaska Division of Oil and Gas told Petroleum News in November.

“To the southwest are ConocoPhillips leases and the Makua wells Conoco is looking at drilling,” he said. While Pioneer is developing a reservoir similar in age to Alpine, there is “also a chance to pick up a Kuparuk reservoir.”

“There’s always been good oil charge in the area from Oooguruk to Alpine,” Van Dyke said.
Looking for hazards on the AK Highway route

DGGS airborne geophysical survey pinpoints locations of geologic faults, areas of permafrost in an important transportation corridor

By ALAN BAILEY

The Alaska Highway corridor survey used a frequency range from 140,000 hertz to 400 hertz to map features from about 5 meters to about 150 meters below the surface. And, because the survey was targeting sediment and rock strata, the electromagnetic coils were configured to emphasize horizontal subsurface features.

Acquiring airborne magnetic and electromagnetic data together provides more criteria to aid in geologic mapping than can be obtained from the individual types of data, some features show up well from magnetic data, while other features can be detected better from electromagnetic data.

The helicopter flew a series of parallel survey lines aligned slightly west of north and one quarter of a mile apart. Fugro Airborne Surveys then used the survey data to derive an electromagnetic profile for every third survey line.

Burns showed some subsurface cross-sections that demonstrated the results of the survey — cross-sections of the subsurface resistance to electrical currents depicted features such as presumed permafrost. A typical section near the town of Tok showed a shallow, electrically resistive layer of presumed sediments lying over a more conductive layer that probably represents the water table. Another resistive layer underlies the conductive layer.

Fault patterns

A complex pattern of faults proved to be a particularly interesting finding from the survey — because of the lack of surface rock outcrops in the area these features were previously unknown. In fact the survey showed a much higher density of faults than existing geologic maps of the surrounding area have depicted. And the vast majority of the interpreted faults appear to slope downwards at steep angles.

A key issue from the point of view of the construction of a transportation infrastructure is the question of which faults are currently active.

“A lot of what we are observing is likely related to older faulting and it will take detailed geologic mapping and geophysical modeling to determine what’s recent and considered a potential geologic hazard,” Burns said.

Surface field mapping

In phase two of the survey project, DGGS plans to do

EXPLORATION & PRODUCTION

Petro-Canada rethinks project

Petro-Canada and its two junior partners may take smaller steps as they move ahead with their Fort Hills oil sands project.

The operator, already behind schedule in releasing a detailed plan for Fort Hills, is now pondering whether to scale back in planned startup from 170,000 barrels per day, said Neil Carmata, senior vice president for oil sands.

The schedule currently calls for the project to come on steam in 2011. Although the ultimate production goal of 340,000 bpd is unchanged, he said staff working on the project have been asked to “go back to the drawing board and look at something smaller” — to see what that looks like and how many people it would take to build.

Does that look easy to pull off?”

Carmata said it may now take three steps to achieve full capacity, once a decision on the first phase and final costs estimates are available by mid-2007, about six months behind the earlier timetable.

But for now, the partnership has filed applications with Alberta regulators for an upgrade near Edmonton. The facility is expected to eventually process up to 340,000 bpd from the Fort Hills mine and other production sources, yielding 280,000 bpd of synthetic crude which would be marketed for refining into gasoline and diesel.

Carmata said the filings show Petro-Canada is serious about Fort Hills, even though it is faced with a “diseconomy of scale” in Alberta because of labor shortages and the rising cost of materials.

He said the bigger the project “the more risk there is in being able to execute it successfully.”

He would not indicate how much smaller the startup phase could be, although there has been speculation it could be reduced to 100,000 bpd.

Petro-Canada owns 5 percent of Fort Hills, with UTS Energy holding 30 percent. Petro-Canada and its two junior partners may take smaller steps as they move ahead with their Fort Hills oil sands project.

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il sands startup Synenco Energy is ready to exploit its Asian connections to ship prefabricated mod-
ules for its Northern Lights project across the Pacific into the Arctic Ocean, then by barge along Canada’s northern river system.

It’s an unstrategically parallel way to avoid labor and materials costs in the oil sands that is already attracting the ire of organized labor.

But Synenco and its 40 percent part-
ner, SinoCanada Petroleum (a wholly owned subsidiary of China’s Sinopec), estimate it can slash their latest estimat-
ed upstream capital costs from C$3.6 billion to C$4.4 billion, or C$49,170 per dail-
y barrel of production to C$36,532.

The approach is “going to be different from other oil sands developers, but it’s one we think is best for our company,” said Synenco President and Chief Operating Officer Todd Newton.

“Our approach should provide relief from the current cost environment (in Alberta) while re-creating the vast cap-
abilities of our partner. ”

He noted that Sinopec is a “function-
ally integrated construction group,” with access to the full array of engineering, technical, fabrication, construction and procurement expertise.

Modules will weigh up to 2,000 tons

The plan calls for building modules weighing up to 2,000 tons — 12 times the size of modules normally built for the oil sands — in China, South Korea or Malaysia. They would then be shipped across the Pacific and into the Arctic Ocean for transfer to barges, which would take about 24 days on the Mackenzie, Slave and Athabasca rivers, as well as crossing Great Slave Lake and Lake Athabasca, to reach the Northern Lights site in northern Alberta.

If components were manufactured in the Edmonton area they would face weight limits on the highway of 175 tons.

The river route got a fresh workout last summer when Northern Transportation Co. operated a tugboat and barge to Fort McMurray in Alberta — the first such voyage since 1979.

The results have convinced Northern Transportation (a partnership of Inuvialuit and Inuit aboriginal enter-
prises) the Synenco idea is feasible, although no contracts have yet been signed.

Synenco has hired AMOEOT, a logistics firm, to coordinate the trans-
portation plan.

The project also includes plans for an upgrader in the Edmonton area, but an update of the budgeted C$3.6 billion for that job won’t be released until 2007. The use of Asian manufacturers is also a consideration for that portion.

But Synenco has said its Asian solution will shrink the on-site construction workforce to about 900 from 2,000.

and 50,000 workers. Synenco has said its Asian solution will shrink the on-site construction workforce to about 900 from 2,000.

Building trades chairman Richard Wassill told the Edmonton Journal that Albertans should be concerned about the prospect of seeing jobs exported as much as the current export of bitumen to upgraders and refineries in the United States.

He suggested Alberta’s new premier Ed Stelmach, who wants measures taken to keep more of the value-added conver-
sion of bitumen into synthetic crude in Alberta, is likely to hear from the unions along with industrial suppliers, fabrica-
tors and truckers.

Newton said Northern Lights will still have a tough job recruiting 900 workers and has not ruled out going overseas to accomplish that task.

He also emphasized that it is much easier to negotiate fixed-price contracts in Asia than it is in Alberta.

Responding to the anticipated criti-
cism, Newton said Northern Lights will generate major benefits for Alberta by creating 1,100 jobs once it comes on stream at an expected 100,000 barrels per day in 2010 — a peak that is project-
ed to last 30 years.

Payout sooner, so royalties go to 25% sooner

In addition, because of the expected cut in capital costs, payout will be achieved sooner, which means royalties soar from 1 percent to 25 percent.

Reflecting the inflationary pressures on the oil sands, the project at one time was estimated to cost C$1.7 billion for the mining and extraction facilities.

But Synenco noted that approximate capital costs per barrel of production have surged from C$100 per barrel in 2003 at Shell Canada’s Athabasca proj-
et to C$200 for Suncrude Canada’s third-phase expansion completed this year, to C$225 for the Long Lake joint venture by Nexen and OPTI Canada and, most recently, something in the range of C$350 at Shell’s Athabasca expansion of 100,000 bpd scheduled to start opera-
tions in 2010.

However, Synenco cautioned that its latest upstream forecast is based on constant 2006 dollars and could still miss the mark by as much as 30 percent on the high side and 10 percent on the low end.

The lease holds 1.67 billion barrels of bitumen in place, an increase of 180 mil-
lion barrels following drilling last winter. The recoverable resource is estimat-
ed at 1.3 billion barrels.

The project also includes plans for an upgrader in the Edmonton area, but an update of the budgeted C$3.6 billion for that job won’t be released until 2007. The use of Asian manufacturers is also being considered for that portion.

Face-to-face with a pledge

Ed Stelmach chose a Friday to be sworn in as the 13th Premier in Alberta’s 107-year history as a Canadian province.

That would suggest he is not prone to superstitious leanings.

But he won’t have much time to revel in his stunning leadership victory.

No sooner was he in office, than he collided head-on with one of his key election pledges.

Stelmach gave priority to protecting the jobs of Albertans in the oil sands by dehy-
dring the loss of high-end employment from the export of raw bitumen for upgrading to synthetic crude in the United States. Just a day after his victory on Dec. 3, he conced-
ed that stopping the shipments is unrealistic, but he plans to take whatever steps are within his government’s power to keep more of the upgrading within the province.

What he likely didn’t count on was the loss of oil sands’ manufacturing jobs to Asia if Synenco Energy and its Chinese partner Sinopec to fabricate components of its upstream and downstream facilities in Asia — a loss of 900 construction jobs at the upstream end alone.

Stelmach has yet to spell out in detail what he can do to keep the upgrading and the manufacturing jobs in Alberta.

But his political opponents have wasted no time pounding on the issue.

Hugh MacDonald, energy spokesman for the Liberal party, said that Synenco’s plan to “do everything offshore is a total sellout of this province.”

New Democratic leader Brian Mason said Synenco’s drastic measures to avoid cost inflation and labor shortages in Alberta should trigger a sweeping review of oil sands developments.

The job facing Stelmach is to tackle the question of whether Alberta is getting value from its own resources, given the indications that the province is being shouldered aside in the extraction and processing of bitumen.

During the leadership campaign, Stelmach, speaking from his experience as a farmer, said that giving U.S. companies a free pass to process bitumen was like “scrap-
ing off the topsoil, selling it, and thinking we have a rich farm because we have cash in the bank.”

He suggested economic incentives might be needed, rather than financial penalties or inflexible rules, to keep the upgrading at home.

“I know we can’t add value to every ton of bitumen, but we can improve,” he said.

MacDonald favors a tougher line, requiring oil sands developers to hire aboriginal, local, provincial and Canadian companies for their construction and procurement work.

Unless action is taken, the Synenco move could put the Alberta steel fabrication industry “in the trench,” he said.

Others, including Andre Piouarde, a University of Alberta energy economist, said the Synenco decision was probably inevitable to arrest spiraling costs.

He cautioned that any moves to curb costs, such as slowing the pace of oil sands development, would only cause investment uncertainty and damage Alberta’s carefully crafted reputation as a good place to do business.

—GARY PARK
Brooks Range files drilling plan

Two wells and a sidetrack will test three North Slope prospects in the Gwydyr Bay area; possibility of an additional well

By ALAN BAILEY & KAY CASHMAN

Petroleum News

Brooks Range Petroleum Corp. has submitted its plan of operations to the Alaska Department of Natural Resources for the company's North Slope winter 2006-07 exploration drilling program. That prospect consists of two wells and a sidetrack targeting three oil prospects north of the Prudhoe Bay unit. The company may also drill an additional well if time permits and if the results from the others look promising.

Brooks Range Petroleum, a wholly owned subsidiary of Alaska Venture Capital Group, has formed a joint venture with TG World Energy Inc., Ramshorn Investments and Bow Valley Alaska Corp. for access to existing seismic data. The company is also negotiating with the major oil producers for onshore immediately south of the Colville River unit. On Nov. 15 at the Resource Development Council annual conference in Anchorage Ken Thompson, managing director of AVCG, said that in addition to drilling exploration wells AVCG/Brooks Range is planning an extensive 3D seismic survey at Gwydyr Bay this winter. And, if time permits, the company will also acquire 3D seismic in the Titana area onshore immediately south of the Colville River unit. The company is also negotiating with the major oil producers for access to existing seismic data, Thompson said.

“Our company is playing a key role in developing new reserves in the main central part of the North Slope,” Thompson said. “As the fields become smaller and smaller in that area, we’ll be looking for 25 million barrels. The company was formed in 2004 to deal with AVCG’s operations, technical services and administrative services.

On Nov. 15 at the Resource Development Council annual conference in Anchorage Ken Thompson, managing director of AVCG, said that in addition to drilling exploration wells AVCG/Brooks Range is planning an extensive 3D seismic survey at Gwydyr Bay this winter. And, if time permits, the company will also acquire 3D seismic in the Titana area onshore immediately south of the Colville River unit. The company is also negotiating with the major oil producers for access to existing seismic data, Thompson said.

“Our company is playing a key role in developing new reserves in the main central part of the North Slope,” Thompson said. “As the fields become smaller and smaller in that area, we’ll be looking for 25 million barrels, to 50 million-barrel fields, hoping we’ll also stumble into a 100 million or 200 million barrel field that still may be left.”

Ice road and ice pad

The winter exploration schedule anticipates constructing an ice road to ice pads once the tundra travel season has opened in December. The first well, the North Shore No. 1, will then be drilled from an ice pad at section 12, township 12 north, range 12 east of the Umiat Meridian. The second well and its sidetrack, Sak River No. 1 and Sak River No. 1A, will be drilled from an ice pad at section 1, T12N, R12E, UM. Both of the ice pads are onshore: the North Shore well will use directional drilling to target a prospect under the Kuparuk River Delta, while the Sak River well and sidetrack will use directional drilling to target offshore prospects under state waters of the Beaufort Sea.

The main ice road will start at the S-Pad in the Prudhoe Bay field and extend approximately six miles north to the Sak River pad, the more northerly of the two ice pads. A short spur ice road will extend east from the main ice road to the North Shore pad. Generally the ice roads will be 35 feet wide and six inches thick. The ice pads will be no larger than 600 feet square and will have maximum depths of two feet under the locations of the drilling rig. An on-site camp will support most of the personnel involved in the exploration activities.

Brooks Range has contracted with Nabors Drilling Alaska to use the Nabors rig 16E for the drilling. Baker Energy, a subsidiary of Michael Baker Corp., will provide oversight of drilling operations and, in the event of an oil discovery, provide engineering, facility design and operations management services, Thompson said.

Jim Winegarner, vice president of land and external affairs for Brooks Range Petroleum, told Petroleum News that the North Shore No. 1 well will target a structural high, updip of a prospect where the Mobil Gwydyr Bay South No. 1 well tested oil in 1974. The target prospect lies in an Exxon, Chevron and ConocoPhillips lease — the lease owners have expressed support for a farm-out for the prospect, Winegarner said.

The Sak River well and sidetrack will target offshore Gwydyr Bay prospects in AVCG acreage.

“Our Sak River No. 1 and No. 1A well will first drill a leg to test what we can see on seismic as a thick upper Kuparuk sand,” Winegarner said. “We’ll come back and sidetrack the well to a structural closure that we see in the lower Kuparuk.”

The Sak River prospects used to be in the BP-operated Sak River unit. BP had planned to drill in the unit in the winter of 2002-03, with AVCG holding a 38 percent working interest in the well. But that well was never drilled and the Sak River unit was later terminated.

Environmentally responsible

Winegarner emphasized the efforts AVCG/Brooks Range has made to support environmentally responsible exploration and development. According to the plan of operations “the proposed ice road and pads were sited to minimize the number of future exploration/appraisal wells needed prior to future development. … In order to use the exploration wells in a development-production effort, the surface locations will be selected to maintain the Beaufort Sea coastline and the Kuparuk River main channel setback distance of 500 feet and one-half mile, respectively.” And the use of directional drilling from onshore well pads will eliminate the need to drill from offshore locations.

“BRPC’s proposed exploration activities were well received by both the North Slope Borough Planning Commission and the Alaska Eskimo Whaling Commission,” the plan of operations says. “Both groups recognize and appreciate the selection of onshore directional drilling, which is the environmentally preferred alternative for field development, for exploration phase activities.”

Thompson also emphasized the critical importance of safety and the environment in AVCG/Brooks Range’s business strategy. He also said that the company is a niche independent, exploring in the central North Slope, onshore near the existing pipeline infrastructure, and also building a portfolio of satellite exploration prospects. Since 1999 the company’s North Slope acreage has grown from a little less than 5,000 acres to about 180,000 acres, he said.

see BROOKS RANGE page 11

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U.S. OKs first FPSO in Gulf of Mexico

MMS approved use of floating, production, storage and offloading systems 4 years ago; Petrobras will use in ultra deep water

By RAY TYSON
For Petroleum News

The federal regulatory agency that oversees oil and gas activities offshore United States has approved what likely will be the first-ever floating, production, storage and offloading or FPSO system to operate in U.S. territorial waters.

The honor goes to three companies headed by Brazil’s Petrobras, an experienced FPSO manager and operator of the yet undeveloped Cascade and Chinook fields in ultra-deepwater Gulf of Mexico. Oklahoma’s Devon Energy and France’s Total’s also hold shares in the Walker Ridge project. The partners anticipate field startup in 2009.

Cascade and Chinook evidently are too distant from the Gulf’s massive sub-sea pipeline system to warrant the expense of a separate oil line that would tie into the existing system. However, Petrobras did not disclose plans for two fields. Under a typical operation, the oil would be produced and stored in an FPSO vessel and later offloaded to a shuttle tanker and transported to shore.

FPSOs are widely used around the globe as an alternative to expensive pipelines. Petrobras alone has an extensive track record in FPSO use in Brazilian waters since 1979, when it first used them. Under such a typical operation, the oil would be produced and stored in an FPSO vessel and later offloaded to a shuttle tanker and transported to shore.

After addressing the potential for oil spills and other environmental concerns associated with FPSOs and shuttle tankers, the Minerals Management Service approved their use in the U.S. Gulf more than four years ago. Earlier this year MMS approved Gulf use four years ago.

Petrobras said it would use six new technologies that have never been applied in the U.S. Gulf, including FPSOs with disconnectable turrets, which allow them to be removed in the event of hurricanes or other storms, oil transportation by relief vessels, submerged pumps, self-sustainable risers, torpedo piles and polyester anchoring lines.

The plan calls for the installation and operation of an FPSO at water depths of about 8,202 feet. In the first phase, two subsea wells in Cascade and one in Chinook, each at a depth of nearly 26,900 feet, would be interconnected.

The oil would then be offloaded by relief vessels and the associated gas via a pipeline. “Depending on reservoir behavior, new wells may be interconnected in the future,” Petrobras said.

Petrobras said detailed engineering studies would shed more light on project specifics, including elaboration of its Deep Water Operational Plan, “which will include the entire technical detailing, demonstrating these new technologies will attend to or surpass current requirements for operations in the Gulf of Mexico.”

Petrobras is the designated project operator with a 50 percent interest in Cascade and a 66.7 percent interest in Chinook. Devon holds a 50 percent stake in Cascade, while Total E&P USA holds a 33.33 percent interest in Chinook.

Fields could be first to produce zone

Cascade and Chinook, in addition to being the first U.S. project to use an FPSO, could be the first offshore fields to produce from the Gulf’s emerging and highly acclaimed Lower Tertiary zone.

The Lower Tertiary play stretches several hundred miles from Walker Ridge westward through Keathley and Alaminos canyons, and is now believed to hold potentially billions of barrels of recoverable oil in dozens of individual prospects primed for exploration drilling based on the positive outcome of a recent production test conducted on the Chevron-operated Jack No. 2 well in Walker Ridge.

Also in the Lower Tertiary race are three Alaminos Canyon oil discoveries — Great White, Tobago and Silverpit — that would produce about 130,000 barrels of oil equivalent per day into a “hub” or centrally located facility.

Project operator Shell is expecting first production from the so-called Perdido Regional Host Project around 2010. The offshore production facility is being designed to gather production within a 30-mile radius of the hub. Other Perdido participants are Chevron, BP and Canada’s Nexen. ●
Tackling the Alaska workforce deficit

Anchorage conference looks at how Alaska’s education, training systems might gear up to address looming shortage of skilled workers

Most of the current debate about an Alaska North Slope gas line revolves around the economics of the line, what route it will take and who will build it. But a massive construction project of this type will require an army of workers. And that’s in addition to the workforce that might be required for other major projects such as a Southcentral gas spur line, new oil and gas field developments, a coal gasification plant at Nikiski and various mining developments.

Where are the skilled workers required for these huge projects going to come from?

Representatives of various Alaska entities involved in workforce development met at an Anchorage Economic Development Corp. conference in October to establish a common understanding of a looming Alaska workforce crisis. A prime purpose of the conference was to develop recommendations for the next Alaska governor and Legislature on how to address the future needs for skilled Alaska personnel.

“It doesn’t matter how many employers or projects we have, if we don’t have the prepared, available and vibrant workforce, Alaska’s going to be in trouble,” said Vince Beltrami of the AFL-CIO, one of the speakers at the conference.

Construction industry growth

The fact that all of the major projects on the horizon involve the construction of industrial facilities and infrastructure places the construction industry and its skilled trades at the center of the workforce problem. Dick Cattanach, executive director of the Associated General Contractors of Alaska, explained that an injection of petrodollars from the burgeoning oil industry fueled an initial construction growth in the late 1970s. And, after a dip in activity during the oil price slump of the mid-1980s, the industry has grown steadily.

“Since that time construction has been in a steady upward growth,” Cattanach said. “… It’s also one of the highest paying industries, paying just under $60,000 per year for construction workers, second only to the oil and gas industry.”

The growth rate has been significantly exceeding U.S. Department of Labor projections of growth of 1.5 percent per year, Cattanach said.

But many of the current construction workers are starting to approach retirement age. For example, 30 percent of carpenters are now over 45 — construction workers tend to retire early.

“Usually by 55 most workers are leaving the industry,” Cattanach said.

The combination of continuing growth in the industry and the high rate of retirement will drive a need for large numbers of new craftspeople. Without even taking into account the needs of new mega-projects, 1,200 new carpenters will be needed over the next decade, Cattanach said.

And that doesn’t take into account a desire to increase the number of workers who are resident in Alaska — 18 percent of Alaska workers are currently non-resident, Cattanach said. Increasing the proportion of carpenters who are resident to 90 percent would raise the quantity of new carpenters required to 2,100 over the decade.

Unfortunately, Alaska is unlikely to be able to import enough new craftspersons because unemployment rates in U.S. urban centers are already quite low and only a portion of unemployed people are interested in entering a craft trade.

“We’re going to have to grow our own,” Cattanach said.

Not enough graduates

But the statistics on the numbers of Alaska school graduates don’t look too promising.

There has been an annual average of about 7,000 high school graduates in Alaska since 1999, Cattanach said. On average 30 percent of these graduates go to college, leaving 4,900 to enter the work-
Canada: 2005 a very good year

But Canada’s conventional spending, drilling in trouble in 2006 and 2007; industry says return to 2005 levels needs strong commodity prices, responsive regulatory environment; CAPP’s oil sands numbers to projects in development or developed

By GARY PARK
For Petroleum News

A benchmark drilling year contributed to some healthy gains in Canada’s oil and gas reserves in 2005, but the jury is out on what to expect this year and next.

In its latest annual update of the numbers, the Canadian Association of Petroleum Producers reports that new established crude oil and natural gas reserves stayed ahead of production.

Conventional crude oil (including mined and in-situ bitumen) surpassed output by 327 percent, ending the year at 1.425 billion barrels, while natural gas replaced 12.3 percent of production, contributing 7.63 trillion cubic feet in gross additions, after production of 6.23 tcf, pushing the total to 57.95 tcf.

Capital spending for 2005 totaled C$45 billion, a figure CAPP estimates will ease off to C$44 billion this year and C$42 billion in 2007.

Natural gas drilling drops from ’05 record

Natural gas drilling set a new record of 15.931 wells in 2005, but the slump in commodity prices this year is forecast to lower the count to 15,400 and produce an even sharper decline to 14,400 in 2007.

Conventional oil wells are projected to slip from 4,210 in 2005 (a 10 percent gain from 2004) to 4,000 this year and 3,900 in 2007.

Total wells are expected to slide from 25,150 to 23,400 in 2006 and 22,000 next year.

That is already reflected in separate industry statistics covering the first 11 months of 2006.

The utilization rate for the average 800 rigs dropped to 63 percent in the January-November period compared with last year’s record 70 percent. The number of inactive rigs averaged 292 to the end of November, up 30 percent from the same period last year and the highest level since 2002.

However, the active rig count of 508 for the November period was six greater than the same month in 2005, an 8 percent gain in the active rig count, making it the second highest on record.

Capitated spending expected to shrink

CAPP estimates conventional capital spending will shrink from C$3.35 billion in 2005 to C$3.33 billion this year and C$2.9 billion next.

Only the oil sands will cushion the impact, edging from C$10 billion last year to C$11 billion in 2006 and C$12 billion in 2007.

CAPP chair Kathy Sendall noted that record spending — three times the outlay of 10 years ago — was needed to achieve the level of reserves growth seen in 2005.

But she said that investment is “only sustainable in a strong price and responsive regulatory environment.”

The association’s outlook for 2007 points to a moderation of conventional upstream activity and conventional capital investment “due to a number of factors, particularly softening gas prices and escalating costs.”

CAPP has calculated that Canada ended 2005 with remaining conventional crude reserves of 5.2 billion barrels, up 20 percent from the 4.4 billion barrels in 2004.

Those additions covered revisions due to drilling, pool reassessment, enhanced recovery schemes and new discoveries, replacing 271 percent of production.

In Western Canada, Alberta dropped by 2.7 percent to 1.7 billion barrels and British Columbia was off 2.9 percent to 100 million barrels, but Saskatchewan posted a 5.2 percent gain to 1.24 billion barrels and Manitoba was up 4.2 percent to 25 million barrels.

The Northwest Territories and Yukon saw reserves drop by 7 million barrels to 36 million barrels, although the Mackenzie Delta/Beaufort Sea, where no commercial development has occurred, is unchanged at 130 million barrels.

The major contributor was offshore Newfoundland, where reserves at the three producing fields — Hibernia, terra Nova and White Rose — dropped to 1.72 billion barrels from 873 million barrels in 2004, due largely to revisions.

Combined mining and in-situ oil sands reserves grew by 16.6 percent to 8.6 billion barrels — a 440 percent replacement rate reflected in the C$10 billion of capital spending.

Developed oil sands mining projects saw reserves grow by 813 million barrels to 6.13 billion barrels, while in-situ reserves gained 18 percent to 2.47 billion barrels.

CAPP numbers short of Alberta energy board

CAPP confines its oil sands numbers to projects that are either developed or where substantial investment has either been made or is under way.

As a result its numbers fall well short of the Alberta Energy and Utilities Board’s estimates of 174 billion barrels of established reserves out of 315 billion barrels deemed to be ultimately recoverable.

On the gas side, the Western Canada Sedimentary basin reserves gained 1.5 tcf, with British Columbia logging year-end reserves of 12.35 tcf after replacing 309 percent of production, a gain of 20.2 percent reflecting an unprecedented year of activity.

A significant portion of B.C.’s gains came from recognition of the Deep basin by the British Oil and Gas Commission.

CAPP said the application of new well completion techniques and three-dimensional seismic took a major role in the development of the Deep basin play.

Alberta replaced 83 percent of production, exiting 2005 with reserves of 40.94 tcf — a loss of 12.9 percent.

Saskatchewan gained 7.8 percent at 3.25 tcf; the Northwest Territories and Yukon were off 5 percent at 400 billion cubic feet and the East Coast offshore tumbled 20.9 percent to 541 bcf because of the continued slide in Nova Scotia’s Sable field.

ALTERNATIVE ENERGY

Comments invited on wind energy test

Alaska Wind Power LLC has applied to Alaska’s Division of Mining, Land and Water for a land use permit for a proposed wind energy test site east of the Richardson Highway, in the vicinity of the Jarvis Creek coal mine area approximately 20 miles south of Delta Junction. Members of the public should submit comments, objections or expressions of interest to the DMLW Fairbanks office by 5:00 p.m. on Jan. 8.

The project would involve erecting 10 wind energy towers on a total of five acres of state land, to assess the wind energy resources available for a possible future wind energy development. Stu Pechek at (907) 451-2733 can answer questions about the permit application.

— ALAN BAILEY
NATURAL GAS

Nexen ready to take control of CBM play

Nexen will not let any financial stumbles by its joint-venture partner get in the way of developing what is potentially Alberta’s largest coalbed methane resource. The Canadian independent will exercise its right to serve notice on any wells that privately held Trident Exploration is unable to support financially, Chief Executive Officer Charlie Fischer told analysts Dec. 6.

But, despite some financial uncertainty and a recent staff layoff, Trident has restored some confidence by arranging a US$270 million loan that enabled it to pay off debts of US$125 million and finance continued development of the Upper Mannville coalbed methane formation.

Recoverable gas estimated at 260 tcf

The two companies are partners in a C$400 million project to achieve the first commercial production from the Mannville, where recoverable gas has been estimated at 260 trillion cubic feet.

While leaving no doubt that Nexen is prepared to act on its rights, Fischer said Trident’s financing deal has eased some concerns about the company’s ability to cover its share of Mannville costs.

He said that conversations with Trident indicate Mannville is “their area of priority and they’re going to do everything they can to stay on track. That’s something we just have to monitor.”

Nexen has budgeted C$200 million for 2007 to continue development of 63,000 acres of the Mannville play.

Fischer said production from the area is expected to grow to 75 million cubic feet per day by the end of 2007 and double that volume by 2011.

The focus is on developing the Upper Mannville assets in the Corbett, Thunder, and Doris fields, using multiple-leg horizontal wells.

—GARY PARK

EXPLORATION & PRODUCTION

No boom from GOM

Thunder Ridge field

Murphy: Deepwater exploration well in Gulf of Mexico encounters wet sands and ‘small oil accumulation’

By RAY TYSON

Field operator Murphy Oil, following deepwater exploration successes at Thunder Hawk and Thunder Bird, appears to have come up short at Thunder Ridge. All three of Murphy’s “Thunder” prospects are within spitting distance of the BP-operated Thunder Horse field, the largest ever oil discovery in the Gulf of Mexico.

The Thunder Ridge exploratory well and sidetrack, drilled on Mississippi Canyon Block 737 in over 6,100 feet of water, encountered wet sands in the primary objective and “a small oil accumulation” in a shallower secondary objective, Murphy said Nov. 30.

“Post-drilling analysis will continue to determine if the resource found can be commercially viable as a tie-back to another facility,” Murphy said of Thunder Ridge drilling results, adding that the Thunder Ridge exploration well was “temporarily” plugged and abandoned.

However, with predrill reserve estimates of 100- to 200-million barrels of oil equivalent, Thunder Ridge’s small oil accumulation would have to be considered a disappointment. Weeks earlier Thunder Hawk was sanctioned as a standalone development with just 50- to 80 million barrels of estimated reserves.

Murphy holds a 37.5 percent working interest in Thunder Ridge. Partners Dominion Exploration & Production, Inc., a subsidiary of U.S.-based Dominion Resources, and Norway’s StatoilHydro Gulf of Mexico each hold a 25 percent share of Thunder Ridge.

Murphy has said that another exploratory well — a sidetrack off the discovery well — would be required before the owners decide whether to pursue development at Thunder Bird.

Thunder Hawk, Thunder Bird and Thunder Ridge are on the edge of the Boarhead Basin, a highly fertile region of the Central Gulf of Mexico that had industry analysts speculating over resource potential before the colossal Thunder Horse discovery was announced in 1999.

Thunder Horse, scheduled to come on stream in mid-2008 after several delays, contains an estimated 1 billion barrels of oil equivalent reserves. The Thunder Horse North satellite contains an additional 400 million barrels of estimated reserves. Owned by BP (75 percent) and ExxonMobil (25 percent), Thunder Horse is expected to produce 250,000 barrels of oil and 200 million cubic feet of gas per day.

Murphy and its partners, before deciding on a standalone facility for Thunder Hawk, considered tying back Thunder Hawk production to the Thunder Horse facility.

—RICK BAZER

Petroleum Facilities Integrity Engineers

State of Alaska

The Department of Natural Resources, Division of Oil and Gas is seeking qualified, experienced applicants for two Petroleum Facilities Integrity Engineer positions to work in the Leasing, Licensing, and Permitting Section. These are permanent, full-time, Range 76, exempt positions. Starting salary will be $80,000 to $125,000 dependent upon experience and qualifications.

Incumbents of these positions will apply education and experience in engineering and/or quality assurance, and the oil and gas industry, to evaluate the design of oil and gas infrastructure and the quality assurance programs of Unit operators and oil and gas leaseholders with the goal of maximizing the integrity of oil and gas infrastructure on state lands. Successful candidates will identify essential elements of acceptable infrastructure design and quality assurance programs and evaluate plans and programs provided by operators against established standards. Incumbents will report to the Petroleum Facilities Integrity Manager, and will routinely participate in briefings with the leasing land manager, director and commissioner regarding operator designs, plans and quality assurance program evaluations.

These positions require an appropriate college degree and/or five years of professional quality assurance experience and familiarity with oil and gas infrastructure systems. Appropriate college degrees would include: Mechanical Engineering, Civil Engineering, Electrical Engineering, Quality Engineering, and Environmental Engineering. Extensive knowledge of the theories, principles, practices and current developments in oil and gas infrastructure engineering, and especially the programs and policies to maintain them in good operating condition, is desired.

The State of Alaska is an equal opportunity employer and supports workplace diversity. Individuals requiring accommodations call 800-587-0430 Voice or 800-777-8873 TTY/TDD (Relay Alaska). Submit a resume with a complete work history and a technical writing sample by 4:00 p.m., December 21, 2006; application materials must be submitted by mail to Sheila Westfall, Administrative Manager, DOG, 550 West 7th Avenue, Suite 800, Anchorage, AK 99501-3560 or by email to Sheila_Westfall@dnd.state.ak.us, in order to be considered for this opening.
force. The construction industry would need 23 percent of those available high school graduates to meet its annual needs, despite the fact that construction only employs about 6 percent of the total Alaska workforce.

Cattanach also said that the current rate of completion of apprenticeships in Alaska only meets about 15 percent of the construction industry's needs. Most construction jobs require on-the-job training, he said.

And Beltrami described the trade union apprenticeship programs, funded by labor and management under joint apprenticeship and training committees.

“Our skill training, on-the-job training and in the classroom, is absolutely unparalleled in my opinion,” Beltrami said, adding that these courses provide a viable alternative to college. “… We have the infrastructure that we’ve built by committing money out of our own pockets, management and labor, to build facilities, curriculum, keeping classroom structures on the cutting edge of our respective trades.”

However, Beltrami said that there is in general a shortage of educated applicants for the programs and that many people struggle with essential math and science skills.

“There’s an inability of many of the applicants that we see to transpose simple fractions on a tape measure into real-world applications needed to turn a blueprint into a building, and that is a travesty,” Beltrami said.

And Jeff Staser, principal of the Staser Group, also emphasized the necessity for entrants to the job market to be work ready. People need verbal and written communications skills; problem solving ability; math and science ability; management skills; and an ability to work with their hands.

So, how well does the Alaska education system prepare people for work?

Career and technical training

Several speakers talked about the issue of integrating career and technical training (otherwise known as vocational training) into school and post-secondary education programs.

Mary Lou Madden, president of Madden Associates, reviewed the results of two past analyses of vocational training in Alaska. The Alaska Department of Education did one of these studies in 1996-97, while the Alaska Department of Labor carried out the other study in 2003. Considerable changes in Alaska vocational training occurred in the time between the two studies, Madden said.

In the 1990s the state funded approved vocational courses for high school students and three out of five students underwent some form of vocational training, Madden said. But although Native corporations and non-profit organizations, particularly for construction, Dave Rees, senior technical resourcing specialist for BP, explained.

Longley said that training programs for Alaska Natives are available with funding through section 166 of the U.S. Workforce Investment Act. And the Cook Inlet Tribal Counsel has made workforce development a top priority—the counsel has opened a large new Anchorage training office that provides a wealth of services, she said.

PARW

Putting Alaska Resources to Work, or PARW, an alliance of the oil, gas and mining industries and of workforce development organizations, is moving ahead with an initiative to tackle the shortage of skilled labor in the industries represented by the alliance members. Although these industries are not in themselves especially labor intensive, major capital projects will require huge numbers of workers, particularly for construction, Dave Rees, senior technical resourcing specialist for BP, explained.

“We’ve got consistent growth in a lot of construction, consistent growth in retirement in the state,” Rees said.

PARW’s planning committee has reviewed studies of workforce development done by other organizations. From these studies the committee identified four main strategies that PARW is now pursuing.

1. Engage the stakeholders in workforce development to “move Alaskans from a vague awareness of the issues to active participation in solving the challenges.”

2. Train the workforce, with a focus on lifelong learning and providing career pathways.

3. Employ skilled Alaskans by communicating specific training needs to training providers and using web-based communications for job placement.

4. Adaptively sustain the training system by adequately funding vocational training.

Recommendations

At the end of the workforce development conference, the conference participants made four main recommendations for the governor and state Legislature.

1. Establish, in collaboration with private sector employers, a clearly articulated career and technical education program in Alaska that has long-term funding. The program should encompass a wide range of different education institutions and should include options such as apprenticeships, internships and private education programs.

2. Establish a career and technical education outreach program where employers can partner with the State of Alaska, the University of Alaska, local schools and tribal partners to help people learn about training, internships, apprenticeships and employment opportunities.

3. Build on an existing Internet-based system that enables prospective employers to find training and job opportunities, and that helps employers find employees.

4. Restructure the Alaska Workforce Investment Board by establishing a direct reporting relationship with the governor, making the board an industry pertinent and establishing full-time professional staff. The board provides policy oversight of state and federally funded job training and vocational education programs.

The conference participants elected not to recommend re-instatement of a state student loan program, nor a suggestion that the state should be required to use apprentices from accredited apprenticeship programs in state capital projects.
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**Business Spotlight**

Hawk Consultants LLC

Hawk Consultants LLC is owned and managed by three professionals — Maynard Tapp, Mike Jens and Dave Norton—who have more than 100 years of combined experience serving Alaska's energy, public works, telecommunications, and private development industries. Hawk professionals provide dependable staff augmentation and management support services to advance client projects from concept to completion, short or long-term.

Verna Fonoti joined Hawk Consultants this year as an administrative assistant and is enjoying learning the ropes of this multifaceted business. Off duty, she plays clarinet and tenor sax in concerts and for fun. She's single, adventurous and believes Nike has the right philosophy: “Just do it.” For Verna, this can apply to anything in life.

Would you like to be here?

Call Susan Crone at (907) 522-9469 for details.

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All of the companies listed above advertise on a regular basis with Petroleum News.
of conventional fields in Alberta, the domi-
nant producing region, along with rising
domestic demand in Canada and a revalu-
eation of the potential for unconventional
production from coal seams and tight gas form-
tations.

It said LNG will be essential to deal with
the shortfall, although delays in building
liquefaction plants, supply constraints at
a number of liquefaction facilities and fast-
rising global demand for LNG will combine
to keep the U.S. LNG market tight until
2012.

However, total net imports of LNG to
the Lower 48 are expected to climb from
600 bcf in 2005 to 4.5 tcf in 2030.

Unconventional plays
threatened by LNG

As those imports start to increase, ana-
lysts such as U.S. consultant Ben
Schlesinger argue in October a cautionary flag
over the future of expensive unconvention-
al plays.

Springing on an oil and gas market out-
look conference sponsored by Canadian
Enerdata, he offered a much bolder view of
LNG's role in meeting U.S. demand, sug-
gest that the U.S. is already launching a
spate of LNG terminal construction.

He said that “without question” North
America will have LNG receiving capacity
by Anadarko of its planned Bear Head ter-
minal in Nova Scotia.

Schlesinger said LNG arriving at the
U.S. Gulf Coast will force the deferral of
natural gas projects because LNG, regard-
less of where it lands, will lower prices.

Four Canadian projects planned

Canada still has four LNG projects that
are planned or under construction — one
in New Brunswick (the Canaport project by
 Irving Oil and Spain’s Repsol), one
in Quebec (the Rabaska project by Enbridge,
Gaz Metro and Gaz de France) and two in
British Columbia (the Kitimat and Westpac
projects).

Schlesinger expects gas-fired power
generation will continue on a growth curve,
adding to Lower 48 demand, with the gen-
ceration sector likely to pass the industrial
sector as the largest customer for gas.

He predicted gas prices will remain on
a volatile path, with Henry Hub prices fluctu-
ating between US$4-$9 per million British
thermal units over the next 12 to 18 months.

On the oil front, the EIA expects
Canada's conventional output to taper off
1.93 million barrels per day in 2010 from
2.12 million bpd in 2005 and then rebound
to 2.01 million bpd in 2015 before dropping
by 1.1 percent annually over the next 15 years.

But it said Canada will play a leading
role in elevating North America's unconven-
tional production from 1.09 million
bpd in 2005 to 1.91 million bpd in 2010 and
2.32 million bpd in 2015, with oil sands
leading the way, followed by liquid-
s from energy crops, natural gas, coal and
shale.

Continued from page 1

ENERGY ACT

Earnings from production from outer con-
tinental shelf leases. According to congres-
sional estimates, that provision could redis-
tribute about $60 billion in federal leasing fees
to the four coastal states over the next 25 years.

On a related issue, Louisiana convinced
a congressional judge in October to halt future
Gulf of Mexico lease sales until environ-
mental damage caused by hurricanes
Katrina and Rita could be thoroughly assessed.
A portion of royalty revenues that
will go to the four states under the new leg-
islation will be used to help clean up the
widespread mess.

“I appreciate the commitment by the
State of Louisiana to use revenues from
these leases to restore coastal wetlands,”
President George W. Bush said in a pre-
pared statement following passage of the
Gulf security act.

The offshore legislation, which is ex-
pected to be approved by President Bush,
ends a 25-year drilling ban in deep waters of
the U.S. Gulf about 125 miles south of
Florida’s Panhandle, but extends a morato-
rium on drilling in other Florida waters until
2022.

Area believed to hold substantial resources

Geologists believe the new area opened
to drilling could hold 1.26 billion barrels of
oil, 8.7 trillion cubic feet of gas, 6.2 billion
barrels of crude and 4.2 billion tons of coal
shale.

Continued from page 1

CUTBACKS

“I hesitate when I say (Western Canada)
is the most expensive market
in the world, but I think it really is.

“So we are going to constrain our
spending there.”

He said competition for equipment,
services and supplies has created a
“highly inflationary cost environment”
in Canada, while a stronger
Canadian dollar has cut into
Devon’s profits.

For now Devon has not released
details of its expected production cuts
in Canada (it has lowered its world-
wide production guidance for 2006 by
1 percent).

But it plans to operate only four rigs
northwest of Fort St. John, B.C.,
this winter, down from seven in 2005-2006

The company also plans to focus
on shallower wells of 4,000 feet or less,
rather than those in the 8,200 foot
range it is already producing.

Devon has been joined by Canadian
Natural Resources in scaling back B.C.
drilling and EnCana could be next in
line when its 2007 budget is released
about mid-December.

The Petroleum Services Association
of Canada, assuming an average gas
price of C$6.25 per thousand cubic feet in
2007, is predicting a 28 percent
decline in B.C. drilling next year to
1,050 wells from the 1,450 expected
this year — the first reversal in the
province since 2001.

Association President Roger Soucy
called the cuts “a signal that which
costs to service, have risen about 30-40 per-
cent in B.C. over the past three years,
driven mostly by the costs of labor and
steel.

Canadian Natural is moving capital
from gas to oil projects, reducing con-
tinental drilling near Fort St. John to
71 wells from 132, suggesting the
emphasis in future years will head
more to LNG terminal construction.

To mirror that view, it is currently
budgeting for 47 conventional wells in
2007, down 71 percent from the 164
planned for 2008 and off 75 percent
from the 186 planned for 2011.

EnCana is likely to shrink its
drilling programs in the prized
Greater Sierra and Cumbath Ridge plays as part
of an overall US$1 billion budget
reduction.

The company’s well count
dropped by 33 percent at Greater Sierra
in the first nine months of 2006 and by
28 percent at Cumbath Ridge.

— GARY PARK
The Alaska Department of Natural Resources said Dec. 14 that all areas of state North Slope and foothills lands remain closed to tundra travel.

“Soil temperatures are cold enough in some tundra areas, but others are still too warm,” DNR said. “Snow depths are below what is required for tundra opening at all stations.”

The foothills tundra opening requires nine inches of snow and a 23 degree Fahrenheit soil temperature at a 30 centimeter depth. The coastal areas require six inches of snow and a 23 degree F soil temperature.

DNR said the east and west coastal areas are mainly cold enough for projects to begin, provided the work takes account of thin snow cover and DNR approval is obtained.

“Lower and Upper Foothills areas need more cold and much more snow,” DNR said. “Only off-road travel with summits, other vehicles or other low-impact vehicles will be authorized.”

Apparently the snow cover is especially low in the Franklin Bluffs area near the Haul Road.

—ALAN BAILEY

On Dec. 1 the Alaska Energy Authority announced that Power Engineering Magazine had named the Chena geothermal plant as "Project of the Year" in the renewables category of an international competition with hundreds of submissions. And hot on the heels of that announcement came the “2006 On-Site Generation Award” from the U.S. Department of Energy and the U.S. Environmental Protection Agency.

Funded in part by an Alaska Energy Authority power project fund loan, the Chena power plant, known somewhat perversely as the “Chena Chiller,” pumps energy out of the ground using a process rather like a reversed refrigerator. Hot water from underground vaporsizes a refrigerant that then powers a turbine generating electricity before being condensed and recycled through the system.

The refrigerant cools the geothermal water, which is then recycled underground.

The truck-sized 400 kilowatt plant, the first of its kind in Alaska, was built by United Technologies to replace a 200 kilowatt gas generator that produced more that 97,500 gallons of diesel fuel per year. Eventually, geothermal energy from the new plant will meet all of the Chena Hot Springs Resort’s electricity needs.

The resort received the DOE/EA award at a ceremony in San Francisco on Dec. 4, in conjunction with the 11th National Renewable Energy Marketing Conference.

The outstanding leadership of companies like Chena Hot Springs.

**PIPELINES & DOWNSTREAM**

EPA fines Flint Hills for clean air violations

The U.S. Environmental Protection Agency has fined Flint Hills Resources Alaska $15,867 for Clean Air Act emergency planning violations at North Pole refinery. The company has also agreed to buy three hazardous substance spill response vehicles and an incident command post trailer for Fairbanks North Star Borough. According to an EPA press release the agency alleged 10 separate violations of the Clean Air Act, including “failure to establish procedures for reviewing and updating the company’s emergency response plan, and failure to establish procedures for informing the public and local emergency response agencies about accidental releases of flammable substances.”

The Clean Air Act requires the development of a risk management program for any facility that manufactures, processes, uses, stores or handles more than a specified amount of regulated substances, including 108 hazardous gases and toxic chemicals.

“Flint Hills needed a better management system to ensure that their emergency procedures were continually updated and also needed a way to inform the public about accidental releases,” said Kelly Huynh, EPA's risk management coordinator.

“Because the program is designed to protect public health and the environment in the event there is an accidental release of hazardous or flammable substances.”

Occurred before purchase

But Flint Hills has told Petroleum News that the Clean Air Act violations at North Pole related to issues that existed at the refinery before the company purchased the refinery from Williams on April 1, 2004. After the refinery purchase Flint Hills hired a third-party consultant to identify any environmental or process issues that existed prior to the purchase, said Jeff Cook, director of external affairs for Flint Hills.

The consultant delivered a report in August 2004 and Flint Hills corrected the problems that the consultant discovered, including the issues that have resulted in the EPA fine.

“All issues were reported and addressed, and we now meet or exceed all regulatory standards," Cook said. “...Safety and the environment are the top priority of Flint Hills Resources.”

—ALAN BAILEY

Chena geothermal project wins national awards

THE NEW GEOTHERMAL POWER PLANT at Chena Hot Springs Resort in Alaska’s interior has won two awards for the innovative use of renewable energy.

The resort received the DOE/EA award at a ceremony in San Francisco on Dec. 4, in conjunction with the 11th National Renewable Energy Marketing Conference.

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**PETROLEUM NEWS** • WEEK OF DECEMBER 17, 2006
field mapping in the highway corridor to verify features identified from the geophysical survey and from air photo interpretations of the area — surface geologic mapping is essential for the refinement and verification of the geophysical analysis and interpretation. The ground mapping will target features identified from the geophysics and then use the geophysical data to extrapolate surface features below the sedimentary cover.

The geologists will also use handheld meters to measure the magnetic susceptibility of all rocks seen in surface outcrop.

An investigation of potentially active faults will involve trenching across each fault and assessing any evidence for the direction and timing of fault movement. Where possible the geologists will verify the actual existence of permafrost in potential permafrost areas identified from the geophysics and air photo interpretations. The field program will also provide a means of calibrating the use of remote sensing data from satellites, for example, to locate areas of permafrost.

Laboratory data, test hole data and records from the 2002 Denali fault earthquake will provide insights into areas where there is potential for liquefaction of the ground during an earthquake. Air photo interpretations and field observations will provide information about potential slope instability. And air photo interpretations, field observations and historical records will provide insights into areas of potential flooding.

Geophysical data available

Meantime, the data from the geophysical survey are becoming available to the public. Maps containing the basic data can be downloaded from the DGGS web site or purchased as paper copies from the division. The original survey data and gridded data used to make the DGGS maps are available from the division on CD or DVD. DGGS hopes to soon make available electrical resistivity profiles and additional gridded data produced from some of the profiles, Burns said.

ALASKA HIGHWAY

A map of aeromagnetic data for part of the Alaska Highway corridor, showing some of the major features that can be recognized.

Pearce with her husband Michael Williams and Vice President Dick Cheney

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ALASKA HIGHWAY

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INSIDER

Resort that is significantly advancing the development of renewable electricity sources through green power markets,” said Susan Carollo, awards coordinator for DOE and EPA.

—ALAN BAILEY

 Pearce sworn in as federal coordinator for Alaska gas line

VICE PRESIDENT DICK CHENEY swore in Drue Pearce Dec. 13 as the first federal coordinator for Alaska natural gas transportation projects. Pearce was confirmed Aug. 4 by the U.S. Senate. Pearce was accompanied at the ceremony by her husband, Michael Williams.

As federal coordinator, Pearce will integrate activities by federal agencies for permitting and construction of a pipeline to bring North Slope gas to markets in the Lower 48. She will report directly to the president.

Pearce said she looks forward “to advocating for the Alaska Gas Project throughout the nation and in Canada.”

In addition to close family and friends, the ceremony was attended by Secretary of the Interior Dirk Kempthorne, Deputy Secretary of Energy Clay Sell, Deputy Secretary of Transportation Maria Cino, Federal Energy Regulatory Commission Chairman Joe Kelliher and Canada’s Ambassador to the United States Michael Wilson.
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