Petroleum news

page 4 Young brings colleagues to Alaska, continues to push ANWR drilling

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Deadhorse sunset

JUDY PATRICK

The setting sun silhouettes oilfield equipment and facilities at Deadhorse on Alaska's North Slope.

ANWR plan leans to wilderness expansion; public comment open

The federal rollout of a draft management plan that could lead to huge new sections of the Arctic National Wildlife Refuge being designated "wilderness," including the potentially oil-rich coastal plain, drew immediate disdain from top Alaska politicians.

The U.S. Fish and Wildlife Service, which acts as landlord for ANWR, is wasting time and money reviewing whether to make more of the refuge wilderness, said Sen. Mark Begich, a Democrat.

"I'll fight every step of the way any effort by federal bureaucrats to close off this enormous source of oil and gas by slapping it with more wilderness designation," he said.

Oil and gas exploration and development already is prohibited in ANWR, but a wilderness designation could harden

see **ANWR PLAN** *page 12*

TransCanada: company still in talks with potential shippers

TransCanada Vice President Tony Palmer told the Alaska Senate Resources Committee Aug. 16 that the Alaska Pipeline Project is on schedule with technical and regulatory matters, but not on the commercial side.

TONY PALMER

TransCanada and its partner ExxonMobil completed an open season for the project July 30, 2010. At that time Palmer said that if things went well, precedent agreements — the commercial side of the project — could be signed by the end of the year.

He told legislators at the mid-August hearing held by the Senate Resources Committee that negotiations are still going on for commercial agreements.

The State of Alaska needs to resolve Point Thomson and gas fiscals issues, Palmer said, and told legislators he was encouraged

see **GAS LINE TALKS** *page 18*

NATURAL GAS

Three in a row

Enstar files new Buccaneer, Aurora & Cook Inlet Energy gas contracts

By ALAN BAILEY

Petroleum News

Southcentral Alaska gas utility Enstar Natural Gas Co. has submitted three new gas supply contracts to the Regulatory Commission of Alaska for approval. One of the contracts, for gas from Buccaneer Energy's newly discovered Kenai Loop gas field on the Kenai Peninsula, commits firm gas supplies after Cook Inlet Natural Gas Storage Alaska's new Kenai Peninsula gas storage facility goes into operation in 2012.

The other two contracts, with Aurora Gas and Cook Inlet Energy, will enable those companies to help bolster Enstar's peak winter gas supplies by participating in the gas bidding system that

The pricing terms appear similar to those in earlier Enstar supply contracts with Marathon, approved by RCA in May 2010, and with Anchor Point Energy, approved by RCA in November 2009.

Enstar pioneered in the winter of 2010-11 — Enstar has insufficient contracted, guaranteed gas supplies to meet projected peak winter demand and has instigated the bidding system to obtain gas to fill shortages on a day-to-day basis.

A provision in the Buccaneer contract will also enable Buccaneer to participate in the bidding process as soon as RCA approves that contract.

see **GAS CONTRACTS** *page 19*

LAND & LEASING

Field fight over?

Alaska, Exxon have 'resolution in principle' on Point Thomson, Sullivan says

By WESLEY LOY

For Petroleum News

A top Alaska official signaled strongly Aug. 15 that the six-year fight for control of the Point Thomson oil and gas field might soon be over.

DAN SULLIVAN

Dan Sullivan, commissioner of the Alaska Department of Natural Resources, told a legislative committee the state and ExxonMobil, the Point Thomson unit operator, have reached "resolution in principle" on terms to settle the legal conflict.

"We believe that this is a resolution that advances the state's interests," Sullivan told the Senate Resources Committee, meeting in Anchorage. "ExxonMobil now is discussing the provisions of the settlement with other working interest owners of the unit, who are also the other litigants in the current lawsuit."

Terms of the settlement remain confidential, Sullivan said.

He noted the matter is more involved than simply the state and ExxonMobil reaching a deal, as the Point Thomson WIOs also are working out "internal commercial terms between themselves."

Sullivan's remarks are the most significant sign yet that the struggle over the rich but undeveloped

see **FIELD FIGHT** *page 20*

PIPELINES & DOWNSTREAM

Beating a path to the Gulf

Enbridge enters contest to build lines from Alberta, Bakken, to Texas refineries

By GARY PARK

For Petroleum News

While its rival TransCanada waits anxiously for the Obama administration to decide the fate of the Keystone XL pipeline, Canada's No. 2 pipeline company Enbridge is on the verge of offering shippers a "huge variety of delivery options," said Chief Executive Officer Pat Daniel.

Topping the list, depending on results from a current round of industry discussions, is a possible 300,000 barrel per day pipeline link from Chicago to Houston, which could come on stream by late 2013 and reduce a growing bottleneck at the Cushing, Okla., trading hub.

The so-called Monarch pipeline carries the

The Cushing bottleneck and high price differentials between West Texas Intermediate and North Sea Brent has climbed as high as US$25 per barrel and is costing Canadian producers as much as C$50 million a day because of their reliance on a single export market, prompting the clamor for an alternative route to Asia.

added advantage of not needing a presidential permit — the major stumbling block for XL — because it does not cross the Canada-United States

see **PATH TO THE GULF** *page 19*

contents

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

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of August 18, 2011.
Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay, Maintenance	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Doyon Yard for Modification	ENI
Dreco 1000 UE	16 (SCR/TD)	Milne Point MPK-02	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD4-210	ConocoPhillips
AC Mobile	25	Prudhoe Bay A-25B	BP
OIME 2000	141 (SCR/TD)	Kuparuk Standby	ConocoPhillips
TSM 7000	Arctic Wolf #2	In Nisku, AB	Available
Kuukpik	5	Preparing to start rig up on Savik #1	North Slope Borough
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 3H-12A	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay Stacked out	Available
Mid-Continental U36A	3-S	Prudhoe Bay Stacked out	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay X-22A	BP
Emsco Electro-hoist	7-E (SCR-TD)	Prudhoe Bay DS12-27A	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay PBU 13-27B	BP
Dreco 1000 UE	9-ES (SCR/TD)	Has been released by Brooks Range Petroleum	Available
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay Stacked out	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay Stacked out	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay Stacked out	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E*	Stacked at Deadhorse	Pioneer
Academy AC electric Heli-Rig	106-E (SCR/TD)	Stacked at Deadhorse	Available
OIME 2000	245-E	Oliktok Point OP18-08	ENI

*Nabors 27-E will be under contract at Oooguruk/Nuna for Pioneer this winter

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site K-05D	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Pad 10 Conducting Maintenance	BP
Ideco 900	3 (SCR/TD)	Kuparuk Drill Site 1D-102	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP (rig built & being assembled by Parker)			
Top drive, supersized	Liberty rig	Endicott SDI for Liberty oil field	BP
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSK-13	Pioneer Natural Resources
Oilwell 2000	33-E	Prudhoe Bay Stacked out	Available

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Drilling NCU 10	Aurora Gas
Cook Inlet Energy			
Atlas Copco RD20 34		Undergoing winterization at W. McArthur River Unit	Cook Inlet Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Beluga 224-23T	ConocoPhillips
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Susan Dionne #7	Buccaneer Alaska
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked	Available
Academy AC electric Canrig	105-E (SCR-TD)	Going to drill for CINGSA and should spud well CLU-3 in next couple of days	CINGSA
Rigmaster 850	129	Kenai Stacked out	Available
Rowan Companies			
AC Electric	68AC (SCR/TD)	Demobilizing and prepping to ship to Lower 48	Pioneer Natural Resources

Cook Inlet Basin – Offshore

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

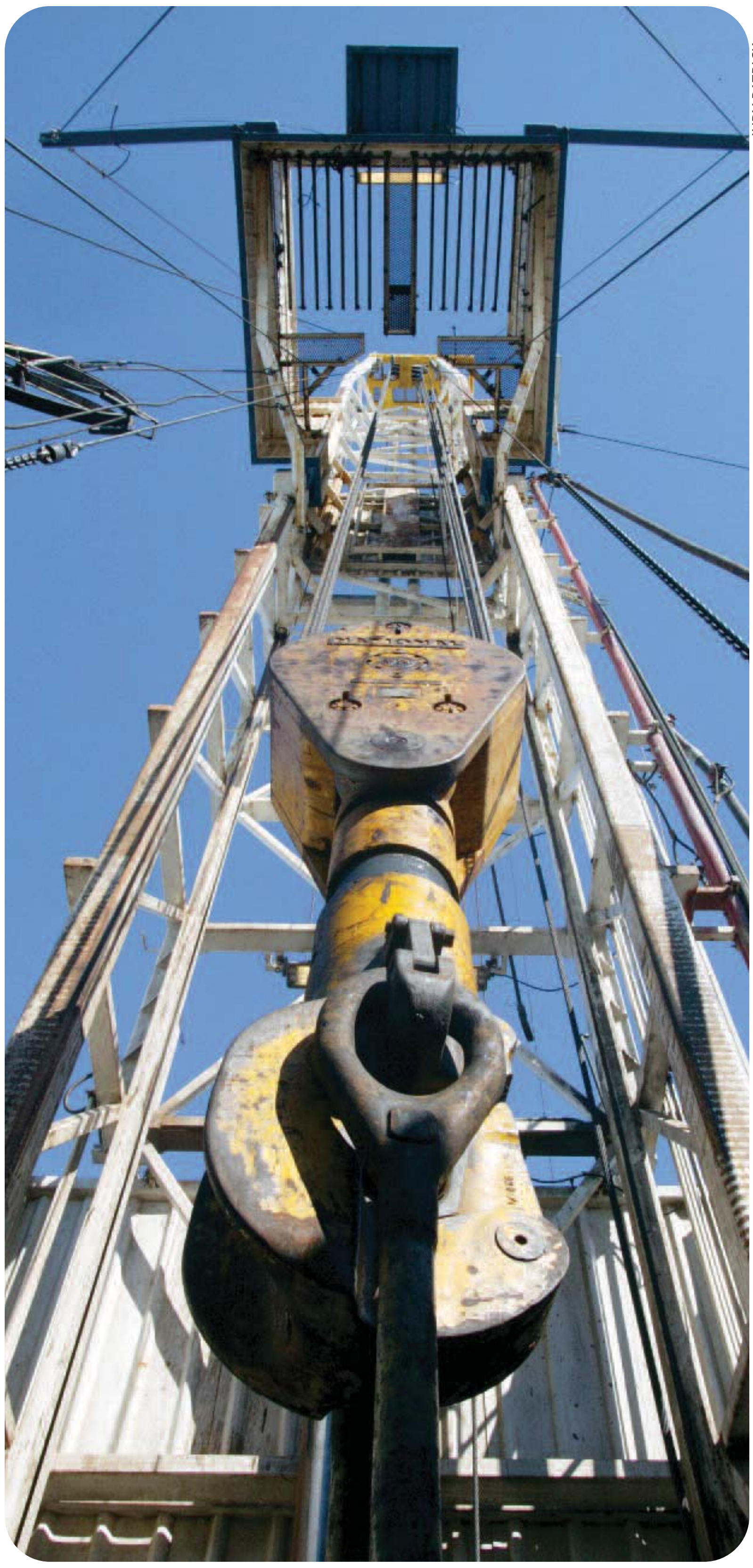
Mackenzie Rig Status

Canadian Beaufort Sea

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

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita/SAHTU			
Oilwell 500	51	Has left the NWT	Available



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	August 12	August 5	Year Ago
US	1,959	1,920	1,640
Canada	464	434	359
Gulf	35	36	20

Highest/Lowest

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

*Issued by Baker Hughes since 1944

GOVERNMENT

Young works to educate federal lawmakers

Alaska's congressman brings colleagues to Alaska, stressing importance of state's resources; continues to press for ANWR drilling

By STEVE QUINN
For Petroleum News

Any federal lawmaker who isn't convinced about the prospects of Alaska's role toward increased domestic oil and gas production and in boosting the economy, check in with Alaska's lone Congressman Don Young.

He'll be happy to show you around the state as long as you're willing to make the seven-hour flight to the state and spend several more hours on a plane surveying the vast fields and Arctic waters that contain billions of barrels of reserves.

Young recently played host to House Resources Committee Chairman Doc Hastings of Washington.

In July the committee passed the NPR-A Access Act designed to expedite permitting.

Young recently discussed Alaska' resource development prospects with Petroleum News, highlighting his intentions to bring more lawmakers to Alaska next year.


REP. DON YOUNG

Petroleum News: Talk about this technique of bringing people like Doc Hastings to the state.

Young: Next year I'm going to bring a group to Alaska. We'll show them Southeast; we'll show them the Railbelt; we'll show them the Interior. So they can visualize the challenges we have, the people who are there and the resources we have. When I see 15,000 high paying jobs leaving Southeast, Alaska — that's wrong. It goes to development of resources. You won't get that employment back until we start manufacturing in the United States. A lot of people say it's the cheap labor overseas. To some degree it is. The reality, labor is relatively high. It's high in Europe. It's relatively high in Japan. In China, they are going huckly buck. It's really not labor. It's the delay and return on investment when we have to go through a process of getting a permit not only from the federal government, but from the state, and from the borough and from the city to put a manufacturing plant in. If it takes 10 years to get your money back why would you invest in the United States? You wouldn't. You'd go where you can get a return in five years. We have become over governed. We are over regulated. It's not just federal. The state is equally as bad.

Petroleum News: Who do you think should come to Alaska to see what it can contribute to the nation?

Young: I want to get key players I'm going to try to get six Republicans and six Democrats that are interested in resource development and investment and see if they can make sure they understand it. They won't always agree because their constituents don't understand it. I remember Sen. Barbara Mikulski of Maryland landed in Prudhoe Bay, went to Kaktovik and said is this it? She went back and voted against it because her people don't know the difference. That's the real challenge. We are a service-oriented state. We have a good fishing industry; we have the mining industry getting better; but the oil is declining, we have no timber industry, so we are living primarily with tourists. So, I'm going to bring people up there to show them and warn them as we fly over so they can visualize it as we land and visit these communities.

Petroleum News: You said six Democrats and Republicans. Does it help to reach across the aisle like that?

Young: I've always done it that way. When I was chairman of transportation, (former Minnesota Congressman) Jimmy Oberstar, he and I worked real close together and we never had an adversarial vote during the six years I was there. We had united 75 members who were very loyal to the committee. That's how we got a lot of things done.

Petroleum News: Why is it taking D.C. so long to view Alaska as a resource state?

Young: A lot of it is our fault. I say that with no doubt in our mind. It's when this whole land battle started. I tried talking Gov. (Jay) Hammond into shutting down the pipeline. It was our oil and draw attention to that. You shut down 2 million barrels of oil and you get their attention about how important this state is. It's a big state. Down here they just don't quite understand that.

Petroleum News: Do you believe people still are taking the oil production for granted with the consistently high price this year?

Young: That's exactly right. We still have people in Anchorage that frankly who don't know their broadside from their backside when it comes to economics. Unfortunately, too many Alaskans, as long as they get their permanent fund dividend checks and they have a job, they are happy. They don't realize that's coming from one source of income, a diminishing source: oil.

That's from Prudhoe Bay, which has been in place for about 35 years. People think well it won't stop. The truth of the matter is that it can stop. That's sad because we have tremendous oil and gas capability in Alaska and the rest of the United States by the way. We have tremendous gas. The (Obama) administration is coming down with new frack regulations to keep them from getting the gas.

That's one reason the economy won't grow back. If we drop gasoline prices to $2.50, every family would have an increased income probably from around $1,500 to $2,000 a year. That would be a great boom for money to buy other things from money which right now they are pouring money down the tank. We sit here on our backside while China is buying everything they can as far as natural resources They have to have 25 million new jobs a year to keep their economy going. They are manufacturing from our natural resources and sending it back to us.

Petroleum News: One of the key battles is ANWR. Why do you keep pushing for it? Some call it a wheel spinning exercise.

Young: I don't believe that. I will pass it out of the House. It will be the 12th time I get it out of the House. The

see **YOUNG Q&A** page 17

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Kay Cashman	PUBLISHER & EXECUTIVE EDITOR
Mary Mack	CHIEF FINANCIAL OFFICER
Kristen Nelson	EDITOR-IN-CHIEF
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Forrest Crane	CONTRACT PHOTOGRAPHER
Tom Kearney	ADVERTISING DESIGN MANAGER
Amy Spittler	MARKETING CONSULTANT
Dee Cashman	CIRCULATION REPRESENTATIVE

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

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● FINANCE & ECONOMY

Canadian oil sands players on edge

Mining projects vulnerable to market turbulence, sliding oil prices; companies without existing operations face greatest threat

By GARY PARK

For Petroleum News

The one constant in the Alberta oil sands is volatility, with the latest round of stock market upheaval and nose-diving crude prices threatening the profitability of future projects and billions of investment dollars.

The greatest anxiety surrounds mining projects, where open pit operations strip away the bitumen deposits that are processed into synthetic crude for further refining.

Bob Dunbar, president of Strategy West, an oil sands consulting firm, estimates that a standalone mine needs oil prices in the $80-$100 per barrel range to be economic.

"Those are the kinds of projects that might be jeopardized if investors take a more pessimistic long-term view of oil prices," he said.

The current pressure is on companies that don't have existing operations and must rely on access to capital markets, which are in a jittery state at present, Dunbar suggested.

Of less concern are the thermal recovery projects, dominated by steam-assisted gravity drainage technology, which injects steam to melt deep bitumen deposits, allowing them to reach the surface.

They probably need an oil-price threshold of $60-$80 to generate acceptable returns, Dunbar said.

Canadian dollar robust

Compounding the numbers problems is the robust Canadian dollar, which has been trading above the U.S. dollar for several months, eating into returns from U.S.-dollar-denominated exports.

If that isn't enough, the Alberta government has also raised the specter of rising interest rates in Europe and the U.S. — a prospect that currently seems unlikely.

But, just in case, Alberta warned earlier this year that a "rapid increase in interest rates and/or disruptions in financial and credit markets could threaten global trade and investment. The high capital-intensity of Alberta's oil sands projects leaves Alberta particularly vulnerable to these shocks, as witnessed in 2009."

Bob Dunbar, president of Strategy West, an oil sands consulting firm, estimates that a standalone mine needs oil prices in the $80-$100 per barrel range to be economic.

Suncor Energy, the largest oil sands producer, reported a foreign-currency charge of $684 million last year.

Adding to the pain has been the growing gap between Canada's heavier crudes and the U.S. light sweet benchmark West Texas Intermediate which is currently running at a gap of $15 per barrel between Western Canadian Select bitumen and WTI.

The challenge is clear for a company such as Suncor, which posted cash operating costs of C$51 per barrel in the second quarter at a time when it is on the verge of final investment decisions with its joint-venture partner Total involving C$21.6 billion to build the Fort Hills and Joslyn mines and the Voyageur upgrader.

Suncor has already shown it will not proceed in a stormy economic environment by delaying the C$6 billion Voyageur project when the financial meltdown occurred in 2008.

Imperial in homestretch

Imperial Oil, owned 69.6 percent by ExxonMobil, has entered the homestretch with construction of the C$10.9 billion first phase of its Kearl mine, which is scheduled to come on line late in 2012 at 110,000 bpd.

Although Kearl's capital costs have reportedly been climbing, Imperial is refusing to flinch, noting the project is expected to have a lifespan of 40 to 50 years.

Already battered and bruised since January by an explosion and fire at its 110,000 bpd Horizon mine, which had previously been a victim of capital cost overruns, Canadian Natural Resources is resolved not to get caught in a repeat experience.

CNR has so far spent C$1.4 billion on the next phase of Horizon expansion and company President Steve Laut estimates capital spending must be kept under C$100,000 per flowing barrel for the project to be economic at US$80 oil.

If the market for labor and materials starts to overheat, he is blunt: "We will take a time out."

To prepare for the worst, CNR said its plans for reaching 250,000 bpd of production have been broken up into five major components, which have been further divided into 46 individual projects, which the company can start and stop at its discretion.

By creating smaller components "we are minimizing the chances of constraining capital and maximizing our ability to control costs and adapt to changing market conditions," Laut said.

Juniors especially nervous

While the majors can ride out shorter-term storms and take a longer-range view of their investments, junior operators, many of them with little or no independent cash flow, are especially nervous.

Harvest Energy, taken over by Korea National Oil Corp. in late 2009, said its BlackGold thermal project has experienced enough cost and schedule pressure to force the company to evaluate ways to minimize the impact on its plans to deliver its first oil in 2013 and produce 30,000 bpd over 25 years.

When the stock markets took their precipitous plunge on Aug. 8, BlackPearl lost 21.3 percent, Petrobank Energy and Resources was down 16.3 percent, MEG Energy fell 11.5 percent and Athabasca Oil Sands was off 10.8 percent, compared with a 6.9 percent decline for Suncor. ●

Contact Gary Park through publisher@petroleumnews.com

LAND & LEASING

DOG approves various land deals in July

Alaska Venture Capital Group LLC completed its acquisition of a bundle of leases on the eastern North Slope in July, according to recent Alaska Division of Oil and Gas files.

BG Group and Arctic Slope Regional Corp. transferred 40 percent and 10 percent working interest, respectively, in 23 leases to AVCG. Anadarko Petroleum Corp. transferred the remaining 50 percent working interest in June. The leases are part of the Greater Bullen unit that AVCG and its partners want to form over 200,058 acres just west of the Arctic National Wildlife Refuge, between the Badami and Point Thomson units.

The division also approved the transfer of 70 percent working interest and 56 percent royalty interest in six Beaufort Sea leases from GMT Exploration Co. LLC to Repsol E&P USA Inc. The deal is one piece of a partnership between the Spanish major Repsol and Denver-based independents GMT and the Armstrong subsidiary 70&148 LLC.

Chevron transferred a small working and royalty interest, less than 5 percent, of one North Slope lease, ADL 390506, to Pioneer Natural Resources Alaska Inc.

Finally, New Energy Alaska LLC transferred several small royalty interests, all in values of 1 percent or less, in two Cook Inlet leases to nine independent investors.

NOTE: A copyrighted oil and gas lease map from Mapmakers Alaska (www.mapmakersalaska.com/) was a research tool used in preparing this story.

—ERIC LIDJI

● NATURAL GAS

In-state bullet line gets questions

Senate Resources Committee members wonder if new Cook Inlet natural gas estimates could make line to Southcentral unnecessary

By KRISTEN NELSON
Petroleum News

The State of Alaska is currently putting money into two gas pipeline projects — a large line from the North Slope to major markets (with spur lines within Alaska) and a smaller line from the North Slope to Interior and Southcentral markets.

The Alaska Senate Resources Committee met in Anchorage Aug. 15-17 to hear updates, starting with Dan Fauske, president of the Alaska Gasline Development Corp., established by the Legislature last year to determine if an in-state line was economic and to have it operational by the end of 2015. (See TransCanada update on page 1 of this issue.)

Available Cook Inlet gas was of considerable interest to legislators, following a recent Buccaneer onshore discovery, the arrival of a jack-up rig to drill for Escopeta and the release of a U.S. Geological Survey estimate of undiscovered resources.

Rep. Peggy Wilson asked what the effect would be of a big Cook Inlet discovery.

Joe Dubler, AGDC vice president and CFO, said the largest impact would be on the amount of liquefied natural gas Enstar would have to import between now and 2019.

Sen. Bill Wielechowski asked if AGDC's work was done before the latest USGS estimates of undiscovered resources, a mean of 19 trillion cubic feet.

Paskvan was concerned about the difference between an estimated tariff to Southcentral, $5.63 before gas and local distribution costs of $2 each, and $6.45 to Fairbanks.

Lieza Wilcox, AGDC commercial analyst, said it was.

Undiscovered resources

Brenda Pierce, USGS resources manager, told the committee Aug. 16 that the estimates are for technically recoverable resources, with today's technology and industry practices, and cover only onshore Cook Inlet and state waters, not the outer continental shelf.

The range of undiscovered natural gas is 5 tcf (at a 95 percent confidence level) to 39.7 tcf (at a 5 percent confidence level). This compares, she said, to cumulative production of natural gas in Cook Inlet of some 7.8 tcf.

This does not include known reserves, Pierce said.

Those estimates are not all accessible — large areas are not open for drilling — and they do not indicate what volume of the technically recoverable would be economically viable, she said.

Pierce said USGS works closely with the Alaska Division of Oil and Gas and the Division of Geological and Geophysical Surveys to understand the rocks, but when it comes to running the numbers, USGS does that by itself.

Resources co-Chair Joe Paskvan noted that the 5 tcf at the 95 percent confidence level, combined with estimated reserves of 1.8 tcf, a total of 6.8 tcf, is in the range of the 7.8 tcf already produced.

Pierce said she thinks there's real potential in the Cook Inlet basin, but co-Chair Tom Wagoner noted that "until somebody proves it's economic we can't count on any of this."

Concerns about demand

Sen. Bert Stedman was concerned about the assumption that there would be export demand, and said he would like to see more assured markets. If the state had $8 billion to spend, is this what we'd spend it on? He asked: Is this the only alternative for power for the Railbelt?

Fauske noted that AGDC only had a year to do the work, and said not all questions can be answered in a year. He also noted that a lot of information, such as the USGS estimate, came in at the end.

But, he said, if there was a large find in Cook Inlet, natural gas could be sent north to Fairbanks.

Wagoner said that while the study takes account of the Watana dam project, there is no mention of the geothermal potential Ormat is working on or Cook Inlet Region Inc.'s coal gas project.

Wilcox described the liquefied natural gas alternative AGDC looked at, with estimated costs at $14 to $19 per million Btu. She said they didn't include all energy options, but that LNG was the most available to fulfill the entire energy demand of the area.

Tariff issue

Paskvan was concerned about the difference between an estimated tariff to Southcentral, $5.63 before gas and local distribution costs of $2 each, and $6.45 to Fairbanks.

Mike Elenbaas, a manager at Black and Veatch, said tariff modeling was based on allocating costs to consumers receiving benefit. Fairbanks pays a lower cost because of the gas going to Anchorage, he said.

Paskvan shot back that there is a lower tariff to Anchorage because of Fairbanks demand, but that Fairbanks bears the cost of a $255 million straddle plant, necessary because the line as modeled carries natural gas liquids and they have to be extracted where a spur line goes to Fairbanks. Ultimate NGL extraction would be at a plant in Southcentral.

Elenbaas said the overall tariff is lower because of NGL content in the gas.

The tariff modeling was based on what would be most defensible in front of regulators, Wilcox said. The cost causer being the cost payer is a principle the Regulatory Commission of Alaska has followed, she said.

Other offtake points could also require straddle plants, she said, calling a "postage stamp" rate — the same rate for all — less defensible.

Paskvan said he was concerned that Fairbanks subsidizes Anchorage and asked about moving NGL through the oil line; he said there had been discussions of injecting NGL south of Pump Station 1 to solve vaporization issues.

Benefit of state ownership

Fauske said a big drop in the tariff, $1 to $1.20, occurs if the state owns the line, because financing would be 100 percent debt and the state has a triple-A rating while most builder-owner-operators have B-plus-plus ratings.

As to who finances, Stedman said the state has typically put in half on hydro projects, and asked how legislators should set fairness across the state.

Fauske said his initial concern had been that the state would have to put up cash, while this proposal is for revenue bonds. It's a policy decision, he said, noting that for equity across the state propane and LNG are possible.

All issues need to be explored, Fauske said, and the product has to beat imported LNG and propane already available.

Where the money goes

Larry Persily, federal coordinator for Alaska Natural Gas Transportation Projects, told the committee Aug. 17 that an in-state line would have many of the same problems as a main line, just on a smaller scale, including a need for fiscal terms.

He said Alaskans need to stop thinking about the big line and an in-state line as competitors and think about how to combine them.

Persily restated remarks he's made in

see BULLET LINE page 12

● ALTERNATIVE ENERGY

FERC holds tidal power scoping meeting

Staff from Federal Energy Regulatory Commission to be in Anchorage in August for Turnagain Arm Tidal Electric Energy Project plan

By KRISTEN NELSON
Petroleum News

Could there be a new island in Turnagain Arm's future — along with 240 megawatts of tidal-generated electricity?

Dominic S.F. Lee of Anchorage is proposing a hydrokinetic energy project for Turnagain Arm which would include a bank of turbines in Turnagain Arm, backed by a water reservoir 1 mile by 2 miles in diameter to store water for use during slack tides.

Federal Energy Regulatory Commission representatives were in Anchorage Aug. 9 for scoping meetings on the proposal.

Lee originally applied to FERC in 2009 for a tidal fence project in Turnagain Arm using Davis turbines. The company sponsor for that project was Anchorage-based Little Susitna Construction Co.

But in a May 10 filing from Turnagain Arm Tidal Energy Corp., Lee told FERC that after further engineering study "it was determined that the Davis turbines deployed in tidal fence arrangement … were considered experimental and were not accepted for current use."

Lee said at the FERC scoping meeting that Turnagain Arm Tidal Energy Corp. was formed in 2009 specifically for the Cook Inlet energy project.

The revised plan, based on a tidal power project in La Rance, France, which has been in operation since 1966, would use a "bulb type of turbine," with a barrage 1,000 feet long and 100 feet wide five miles from Possession Point near Fire Island.

Lee said the bulb-type turbines have been in operation at La Rance for more than 45 years with no recorded breakdowns.

The construction cost is estimated at $760 million, Lee said, and would produce 240 megawatts of power.

Reservoir 1 mile by 2 miles

The barrage would be backed by a reservoir 1 mile by 2 miles — a storage tank for water to be used to drive the turbines during slack tide. The height of the tank would be 20 feet about high tide.

Lee said that while tidal power is predictable, it is intermittent because of the slack tide period — hence the storage tank. He said the slack tide in Turnagain Arm is short, 15 to 30 minutes, and the reservoir provides moving water for energy production during the slack tide.

The project would be in Turnagain Arm, southwest of Fire Island, with a submerged cable running onshore to a switch yard in Anchorage and onshore to a control building on Point Possession at the northern end of the Kenai Peninsula.

A new island

Lee said at the morning scoping meeting that Turnagain Arm is an ideal place for tidal power because it has the fourth-highest tides in the world. He said the Rance Tidal Power Station in Brittany has been producing continuously since 1966 and providing power at 1.2 cents per kilowatt hour since costs were paid off in 1986. Because the tidal power project in Brittany is connected to the national power grid, slack tide isn't an issue with that project, he said.

But Anchorage is not on a national grid, so the storage tank provides water to move the turbines during slack tide.

Slot gates would be open during flood tide and closed in ebb and slack tide. During flood tide a pump system would fill the storage tank to 10 feet above high-tide level and during slack tide slot gates would be raised and the turbines would be turned by water coming out of the storage tank.

The reservoir would have a concrete wall surrounded by rock. Lee said the barrage and reservoir would function as an island; fish and sea mammals can swim around it and it may provide habitat for birds and sea mammals, he said.

Wildlife questions

In response to a question about fish studies for the French project, and whether there were whales in that area, Lee said that fish 3-4 feet long swim through the French project. He said the turbines turn slowly, slower than a revolving hotel door.

Beluga whales, he said, would be blocked from the turbines in the Turnagain Arm project.

Asked whether fish could be trapped in the reservoir, Lee said water flows in and out and the gates open and close, so fish could get in but could also get out when the gates are open.

Asked about rock for the project, Lee said TATEC has a memorandum of understanding with a rock quarry owner who has 15-30 million cubic yards available; the project, he said, would need 10-12 million cubic yards.

Asked about screening for water being pumped into the reservoir, Lee said water would be drawn from an area more than 180 feet deep, where fish are not expected. The project area itself is in water about 60 feet deep.

Other questions and issues from regulators — including the Alaska Department of Fish and Game, the U.S. Fish and Wildlife Service, the National Park Service and the National Marine Fisheries Service included: impact of pumping on marine species; ice formation in the tank in winter; affect on hydrology in Cook Inlet and on some deeper channels in the inlet that may be important to belugas; possible changes in tidal regime due to changes in geometry and bathymetry of Cook Inlet; possibility of sedimentation around a new island; ability to see sediment buildup in inlet conditions; whether project would cause more channel movement in Turnagain Arm; and whether an island a mile wide would impact bore tides in 18-mile wide area.

EIS required

Kim Nguyen, the FERC project engineer, said an environmental impact statement will be required for the project.

She said agencies need to submit study requests and comments within 30 days under the integrated licensing process for the license.

There is a six to eight month period for FERC to define study plans, Nguyen said.

A second scoping document, if needed, would be issued Oct. 24; there is a resolution process for any study disputes scheduled for April through June of next year. The first study season would be in 2012; if necessary a second study season would be held.

TATEC would file a preliminary licensing proposal in September 2014; a final EIS would be issued in July 2015 and a license order in September 2015. ●

Contact Kristen Nelson at knelson@petroleumnews.com

Agencies to begin hydrokinetic studies

The State of Alaska is interested in gathering data on Cook Inlet hydrokinetic energy.

The Alaska Energy Authority said Aug. 16 that it has signed a memorandum of agreement with the National Oceanic and Atmospheric Administration to conduct a baseline assessment of tidal hydrokinetic energy in Cook Inlet.

AEA said that over the next few years NOAA will be measuring and modeling water levels and three-dimensional current, salinity and temperature fields within Cook Inlet to identify regions with promise for the generation of hydrokinetic energy.

"We are pleased to partner with NOAA on this project," said Peter Crimp, AEA alternative energy and energy efficiency deputy director. "Many Alaskans know the power of Cook Inlet tides, and through these studies we will gain valuable information for harnessing that power."

AEA and NOAA will hold a stakeholder meeting from 8:30 a.m. to 5 p.m. Aug. 24 at the Clarion Suites Downtown, 1100 West 8th Ave., Anchorage.

AEA said the agencies hope to gather input from stakeholders with interest in Cook Inlet hydrokinetic energy to compile needed observations, engineering requirements and environmental considerations.

The meeting is open to the public.

—KRISTEN NELSON

● GOVERNMENT

USCG commandant outlines Arctic needs

Papp emphasizes importance of U.S. icebreakers, support infrastructure and emergency response capabilities as sea ice recedes

By ALAN BAILEY
Petroleum News

For several years the U.S. Coast Guard has been making moves towards a heightened presence in the seas around Alaska's Arctic coastline, as summer sea ice retreats in response to global warming. And, with companies like Shell anxious to move forward with exploratory drilling on the Arctic outer continental shelf, as well as increased vessel traffic in newly accessible Arctic sea routes, many view ramped up Coast Guard operations north of the Arctic Circle as a necessary component of the changing Arctic world.

On Aug. 12 in Anchorage, Alaska, Sen. Mark Begich convened a field hearing of the U.S. Senate Oceans, Atmosphere, Fisheries and Coast Guard Subcommittee, to hear testimony from Admiral Robert Papp, USCG commandant, on the future of the Coast Guard in Alaska.

ROBERT PAPP

"I can report that our Coast Guard is ready to meet our mission demands, but we're also facing many challenges," Papp said. "There is increased vessel traffic, including large foreign tankers using Russia's ice-free northern sea route which exits through the Bering Sea into our richest fishing grounds."

Limited capabilities

The Coast Guard has very limited Arctic emergency response capabilities, no infrastructure on Alaska's North Slope to support its operations and only one operational Arctic icebreaker, he said. And, with the necessity to deploy personnel to remote locations around Alaska, providing adequate accommodation for those personnel, as well as appropriate support facilities, at a time of budgetary constraints presents a significant challenge.

Papp said that he is not yet certain whether some kind of regional committee is needed for community liaison in the Arctic.

From the perspective of offshore oil spill prevention and response, as industry oil exploration advances, the Coast Guard currently has no pollution response capabilities and, working in conjunction with the U.S. Department of the Interior, is entirely dependent on ensuring that oil companies have adequate response resources in place, Papp said.

"While oil companies can assert that they have sufficient assets on site to respond to a worst-case (oil) discharge scenario, prudence dictates that we also acquire an appropriate level of (federal) Arctic pollution response capabilities. Presently we have none," Papp said.

After the hearing, Papp told Petroleum News that the Gulf of Mexico Deepwater Horizon disaster had demonstrated the impossibility of knowing everything that can possibly go wrong with an offshore operation and, that without the necessary response equipment available, people end up in a "stern chase," trying to catch up with the situation. So, although it is essential to ensure that companies have the appropriate response equipment to support their operations "we should have some level of federal response equipment as well, so that we can join the fight and we can take care of those unexpected incidents or consequences that might develop," Papp said.

Papp also expressed concern about the lack of pre-authorization for the use of dispersants to respond to an Arctic offshore oil spill.

"We would like to have that in our tool pack," he said.

New cutters

As part of his testimony Papp said that the Coast Guard is in the process of acquiring eight national security cutters, to conduct high-seas missions such as fisheries patrols in the Bering Sea. These high-endurance cutters need to be able to operate anywhere from the Gulf of Alaska up to the Arctic Circle and beyond, he said. The first of the cutters has already gone into service and successfully demonstrated its ability to conduct operations such as launching and recovering boats and helicopters in sea conditions that would have previously rendered these operations impossible.

The second and third of these cutters are nearing completion; the cutting of steel for number four is under way; and contract negotiations for the construction of number five should be completed shortly, Papp said.

Need icebreakers

However, the fact the Coast Guard now only has one operational icebreaker presents a major challenge when it comes to operations in Arctic waters. Having ice-capable surface assets is vital for scientific research and the maintenance of sovereignty, as well as for the provision of emergency response assistance. A surface ship, as distinct from an aircraft, can break a ship out of the ice and tow it, Papp said.

Questioned about the possibility of leasing icebreakers, given U.S. budgetary constraints on building new vessels, Papp said that, while this is an option worthy of consideration, leasing presents the risk of a vessel not being available when the U.S. needs it — perhaps some mix of icebreaker ownership and leasing might be a solution to the icebreaker shortage, he suggested.

Ice-capable buoy tenders

Papp said that the Coast Guard is considering future roles for the 16 ice-capable buoy tenders that it owns, with a plan to bring two of these vessels up to the U.S. Arctic in the summer of 2012. These vessels have demonstrated a capability to break ice on the Great Lakes and the Coast Guard deployed one of the vessels in the Canadian Arctic this summer. The main

see PAPP VISIT page 9

● EXPLORATION & PRODUCTION

Oil tops Western Canada drilling

By GARY PARK
For Petroleum News

Western Canada's petroleum industry is riding an oil wave, with Alberta tallying 2,556 development wells in the first seven months, the highest point in 30 years of record-keeping.

The four western provinces of Alberta, Saskatchewan, Manitoba and British Columbia racked up 3,727 development completions in the January-July period, 62 percent of completions for oil, gas, service and dry wells, up 1,293 from the comparable oil count in the same timeframe last year.

Exploratory completions have also posted solid gains at 554, compared with 407 a year ago, but exploratory drilling has accounted for only 17 percent of all drilling so far this year, marking a continued decline.

The swing to oil, despite some volatility in crude prices, looks certain to continue over at least the next year, with regulators in Western Canada issuing 6,678 permits (which are valid for 12 months) for new oil wells, up 49 percent from the same seven-month period last year, while the total well permits rose 20 percent to 10,388, the highest total since 2008.

A total of 43.6 million feet of wells were drilled to the end of July, including 2.9 million feet in July, which is typically the low point for the year.

A record 5,204 or 50 percent of the permits issued to the end of July were for horizontal wells, compared with 16 percent in 2008.

Completions up by a third

Industry and government regulators reported that 8,120 wells were completed across Canada in the seven months, up 33 percent from last year's 6,102 completions.

The breakdown includes 4,295 oil wells, 2,755 gas wells, 827 service wells and 253 dry holes.

Saskatchewan was second to Alberta, with 1,492 oil completions, up 401 from last year, while Manitoba dipped to 194 oil completions from 204.

An estimated 500 wells were completed across Canada in July, including 300 oil wells and 97 gas wells.

A total of 43.6 million feet of wells were drilled to the end of July, including 2.9 million feet in July, which is typically the low point for the year.

Operators securing the most horizontal permits were Canadian Natural Resources 357, Penn West Petroleum 265, Crescent Point Energy 240, Husky Energy 188 and Encana 182.

The most popular zones were Viking at 745 licenses, Montney 556, Cardium 545, Bakken 359 and McMurray 198.

The license count includes 1,083 oil sands evaluations, up from 783 a year ago and the most since 2008 when the total was 1,737.

Regulators issued 893 permits for oil or bitumen targets in July, up from 757 in July 2010 and the highest in a decade.

Of the seven-month total, 3,562 oil permits were authorized in Alberta, up from 2,280 last year; 2,756 in Saskatchewan, up from 1,766; and 324 for Manitoba, down from 325.

Gas and coalbed methane permits remained at a decade low 311 in July, down 47 from last year, and lagging far behind the peak 1,645 in 2004. ●

Contact Gary Park through publisher@petroleumnews.com

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PAPP VISIT

limitation of a vessel of this type is the lack of a helicopter flight deck and hangar, he said.

The Arctic deployment of two buoy tenders in 2012 would help achieve a goal of maintaining the presence of at least one Coast Guard vessel at all times when Arctic offshore oil exploration starts, as well as providing the Coast Guard with more experience of Arctic operations, Papp said.

Papp also stressed to the subcommittee the importance of engagement with local communities, saying that the Coast Guard becomes part of each community to which it is assigned, listening to what people have to say; promoting safety and security; and partnering with local people to do whatever needs to be done.

Papp told Petroleum News that the Coast Guard built oil skimming capacity into its buoy tenders, a feature that could prove valuable given the difficulty of Coast Guard access to skimmers owned by oil spill organizations but under contract to industry.

Community engagement

Papp also stressed to the subcommittee the importance of engagement with local communities, saying that the Coast Guard becomes part of each community to which it is assigned, listening to what people have to say; promoting safety and security; and partnering with local people to do whatever needs to be done. He said that he had just spent nearly two days on the North Slope, listening to Mayor Itta of the North Slope Borough, the borough assembly and various members of the community. Papp said that he is not yet certain whether some kind of regional committee is needed for community liaison in the Arctic. The Coast Guard must listen to community concerns but may not need something as formal as a committee to do that in the Arctic, he said. ●

Contact Alan Bailey at abailey@petroleumnews.com

● PIPELINES & DOWNSTREAM

Settlement reached on pipeline tariff

Cook Inlet gas producers, utilities agree on booking and fee arrangements for transporting gas in key part of Beluga gas line infrastructure

By ALAN BAILEY
Petroleum News

The parties to a Regulatory Commission of Alaska investigation into a proposed new tariff for the Beluga gas pipeline on the west side of Cook Inlet have reached a settlement over the terms of the tariff and have asked the commission to approve the settlement within 30 days.

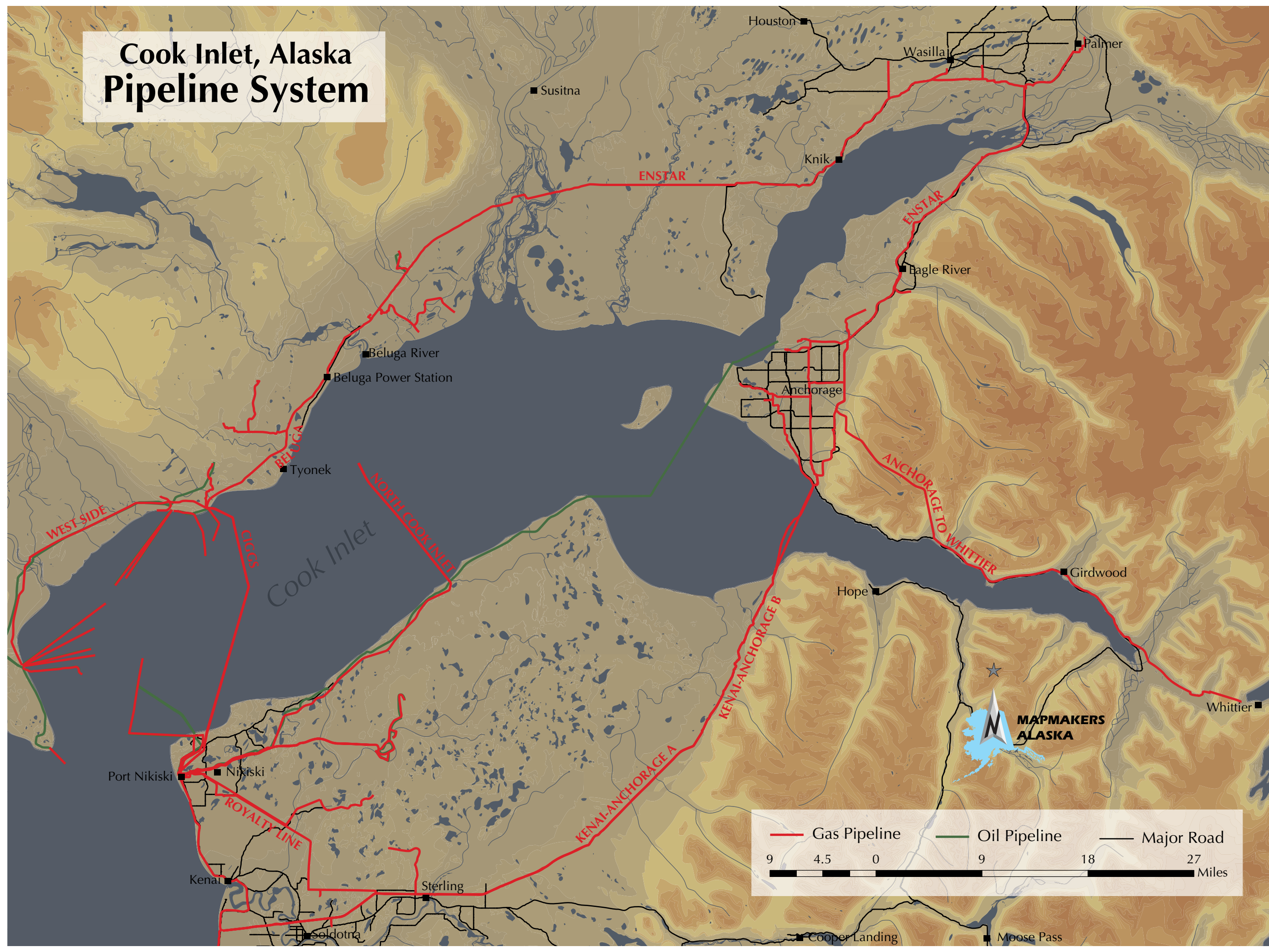
The 100,000-cubic-feet-per-day capacity Beluga line connects gas fields on the west side of Cook Inlet to Chugach Electric Association's Beluga gas-fired power plant and to the southern end of Enstar Natural Co.'s gas transmission line that carries gas north into the Matanuska-Susitna Borough area. With the line being a critical link in the natural gas infrastructure on the west side of the inlet, the tariff on the line is of great importance in determining how gas producers and utilities transport gas to market, and in determining the cost of that gas on delivery.

New tariff

In December 2010 Beluga Pipe Line Co., a subsidiary of Marathon Oil Co., filed a new tariff proposal, involving an annual fee of $46.67 to reserve one thousand cubic feet per day of line capacity, rather than charging for the volume of gas actually shipped. The tariff would have enabled the shipping of gas in unreserved capacity under certain circumstances, but at a greatly elevated volumetric fee of $2.5416 per thousand cubic feet. Beluga Pipe Line had been charging its customers 25.44 cents per thousand cubic feet to transport gas on the line.

Beluga Pipe Line said that the new tariff was addressing the problem of shippers only using its line during spikes in gas demand, especially during the winter, a usage pattern that renders a traditional volume throughput fee impractical to operate. But the tariff proposal provoked a flurry of questions from gas shippers, concerned about the cost impacts of perhaps having to reserve more pipeline capacity than they need, or having to incur high fees for using unreserved space.

And the various parties involved in the debate embarked on negotiations, assisted by an RCA-appointed judge, to find a mutually agreeable tariff solution.



MAPMAKERS ALASKA

The Beluga gas pipeline runs between the Cook Inlet Gas Gathering System, or CIGGS, and the Beluga power plant on the west side of Alaska's Cook Inlet. The line can provide route to carry utility gas from the west side of the inlet into the Matanuska-Susitna valleys and Anchorage. However, much west-side gas destined for Anchorage currently flows through a Kenai Peninsula line via CIGGS under the Cook Inlet.

Choice of methods

Under the terms of the resultant settlement, gas shippers will be able to continue to transport gas on the line at the current rate of 25.44 cents per thousand cubic feet, but without a guarantee that there will be space available on the line to ship the gas. Shippers will be able to pre-book guaranteed capacity on the line at a cost of 25.44 cents per thousand cubic feet per day, a cost that would equal the current cost of using the line if a shipper uses all of its reserved capacity. Any unused capacity can be carried forward for use at a later date in the same contract year.

And, as part of the settlement agreement, Chugach Electric Association and gas utility Enstar Natural Gas Co. signed five-year contracts reserving capacity on the line. CEA has reserved a capacity of 21 million cubic feet per day for each year, while Enstar has reserved 4 million cubic feet per day in year one, declining to 2 million cubic feet per day in year three and reserving no capacity in years four and five.

Pipeline infrastructure

Enstar operates two gas transmission lines for the delivery of utility gas into main gas demand centers in the Municipality of Anchorage and the Matanuska-Susitna Borough. One line runs north from the west side of Cook Inlet and one, on the east side of the inlet, runs north through the northern Kenai Peninsula. Another gas line called the Cook Inlet Gas Gathering System, or CIGGS, runs under Cook Inlet and carries gas from oil and gas fields on the west side of the inlet into the gas pipeline infrastructure on the Kenai Peninsula, including the Enstar transmission line on that side of the inlet.

Although CIGGS connects with the southern end of the Beluga pipeline, and hence with CEA's Beluga power station and with Enstar's transmission line running north into the Matanuska-Susitna Borough, gas producers on the west side of the inlet have tended to ship their gas through CIGGS to the Kenai Peninsula for delivery to market. This pattern of gas movement appears to result, at least in part, from the fact that gas being delivered into CIGGS on the west side of the inlet can be transported through CIGGS to the east side of the inlet at no incremental cost, while also avoiding the cost of moving the gas through the Beluga line.

Flexibility needed

However, the Cook Inlet gas industry is changing significantly, thus driving a

see **SETTLEMENT** page 11

● FINANCE & ECONOMY

EIA expects refiner crude cost of $100

Agency's August short-term outlook based on global spare production capacity, assumes US GDP growth of 2.4%, 2.6% this year, next

By KRISTEN NELSON
Petroleum News

Based on U.S. real gross domestic product growth of 2.4 percent this year and a continued decline in global spare production capacity, the U.S. Energy Information Administration estimates that the refiner acquisition cost of crude oil in the U.S. will average $100 per barrel this year and, with 2.6 percent GDP growth in 2012, $107 per barrel next year.

In its Aug. 9 short-term energy outlook EIA said its "assumptions do not fully reflect recent economic and financial developments that point towards a weaker economic outlook and also contributed to a sharp drop in world crude oil prices during the first week of August."

The agency said there "is a significant downside risk for oil prices if economic and financial market concerns become more widespread or take hold."

Supply disruptions an issue

EIA said global oil demand growth, led by China, is expected to outpace growth in supplies outside the Organization of the Petroleum Exporting Countries. As a result, markets will rely on drawdown of inventories and OPEC production increases, but the agency said OPEC countries are not expected to increase production markedly in the short term.

Major upside risks in the crude oil price outlook include additional supply disruptions in producing regions and higher-than-expected demand growth, particularly in countries outside the Organization for Economic Cooperation and Development. EIA said downside risks include rate of global economic recovery and fiscal issues facing national and sub-national governments.

Non-OPEC supply is expected to increase by an average of 650,000 barrels per day of crude oil and liquid fuels, with the greatest increasing in Brazil, Canada, China, Columbia, Kazakhstan and the United States, each averaging growth of more than 100,000 bpd. Production declines are expected in the North Sea of 140,000 bpd, particularly in the United Kingdom, and declines in Yemen of 140,000 bpd based on ongoing strife.

Spot prices down

West Texas Intermediate crude oil spot prices fell from an average of $110 per barrel in April to $97 per barrel in July, EIA said, with world crude oil prices falling by about $10 per barrel in the first week of August, "reflecting market concerns about world economic and oil demand growth."

The agency said it expects oil markets to tighten as the demand for liquid fuels grows in emerging economies, continuing to outpace supply growth and putting upward pressure on oil prices.

EIA said it expects WTI to average $96 per barrel this year and $101 per barrel in 2012, up from $79 last year.

Gas consumption grows

Natural gas consumption rose with the extremely hot weather in most of the nation in July, with U.S. population-weighted cooling-degree days 27 percent higher than the 30-year norm and 8 percent higher than last year, contributing to an increase in natural gas use for electricity generation compared with July 2010.

EIA said it expects that total U.S. natural gas consumption will grow by 1.8 percent to 67.4 billion cubic feet per day this year, with forecast industrial and electric power consumption growth making up most of the increase.

U.S. marketed natural gas production is expected to average 65.5 bcf per day this year, a 3.7 bcf per day (5.9 percent) increase over last year, with growth centered in onshore Lower 48 production, which more than offsets projected declines in the outer continental shelf Gulf of Mexico.

Growing domestic natural gas production is reducing reliance on imports, EIA said, and contributing to increased exports.

The Henry Hub spot price averaged $4.42 per million Btu in July, 13 cents lower than the June average. EIA said it expects the Henry Hub price will average $4.24 per million Btu this year and $4.41 in 2012, reflecting some tightening in supply as domestic production growth slows. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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SETTLEMENT

need for greater flexibility in the way in which gas is shipped. Changes include the development of new gas fields on the east side of the inlet, the imminent mothballing of an LNG export terminal at Nikiski on the Kenai Peninsula and the development of a new gas storage facility near the City of Kenai. In addition, ever tightening gas supplies from the Cook Inlet basin require utilities and gas producers to be able to make nimble changes to gas delivery routes, to ensure that gas can be delivered efficiently from gas wells to gas consumers during periods of peak gas demand.

Companies involved in the Cook Inlet gas industry have for some time been negotiating technical and commercial arrangements for bi-directional flow in CIGGS, arrangements that would enable gas to be shipped east to west under Cook Inlet and up through the Beluga line, when appropriate.

Bi-directional flow on CIGGS would add greatly to the flexibility of gas transportation around the Cook Inlet basin, including the shipment of much needed gas from storage during peak winter demand. But, pipeline tariffs, including the tariff on the Beluga line, play an important role in determining the price paid for that flexibility. ●

Contact Alan Bailey at abailey@petroleumnews.com

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ANWR PLAN

that policy.

U.S. Sen. Lisa Murkowski, the top-ranking Republican on the Senate Energy and Natural Resources Committee, argued the Fish and Wildlife Service lacks authority under ANILCA, the Alaska National Interest Lands Conservation Act of 1980, to even study designating more wilderness in the state.

"Instead of trying to lock up our resources, we should be developing them as part of a balanced energy plan that creates jobs and bolsters our failing economy," Murkowski said. "There's a tremendous amount of money buried in the ground in Alaska, and it's time to withdraw it."

Alaska's Republican governor, Sean Parnell, also objected to the draft 15-year management plan for ANWR.

"This is another unfortunate effort by the Obama Administration to prevent Americans from developing Alaska's vast resources for the benefit of the country," Parnell said.

Conservation groups encouraged

Conservation groups, as well as a group representing indigenous Gwich'in people, hailed the prospect of expanding wilderness within ANWR, the protection of which has long been a top priority for the environmental community.

"We are encouraged that the Fish and Wildlife Service is considering Wilderness recommendations for the coastal plain, the biological heart of the Arctic Refuge," said Dan Ritzman, Alaska regional director for the Sierra Club. "For decades Americans from all walks of life have asked for permanent protection for these critical lands and waters and now they have the opportunity to move this one step closer to reality."

It's far from assured that more ANWR acreage will be designated wilderness. Such a measure would need to clear several approvals before winning the ultimate OK from Congress

"The Arctic Refuge is one of the country's most treasured, pristine places, and as of yet remains unspoiled by widespread industrial scale oil and gas operations," said Jamie Rappaport Clark, executive vice president of Defenders of Wildlife. "The Fish and Wildlife Service should seize the opportunity to strengthen protection for the refuge and its diversity of wildlife against the threat of Big Oil and pursue a wilderness recommendation."

"Since President Eisenhower established the Arctic Refuge in 1960, our nation has acted to embrace the bold wilderness vision of the refuge's founders and to protect it from oil and gas interests. In the face of climate change and a renewed push to develop the Arctic for oil and gas, our country's leaders should support the wishes of Americans by taking the necessary steps to permanently protect the Arctic Refuge's coastal plain — a globally significant, vital homeland and birthing ground for millions of birds, polar bears and caribou, as well as a critical subsistence resource," said Nicole Whittington-Evans, Alaska director for The Wilderness Society.

'Preliminarily recommended'

It's far from assured that more ANWR acreage will be designated wilderness. Such a measure would need to clear several approvals before winning the ultimate OK from Congress.

The Fish and Wildlife Service in April 2010 began work to revise what's known as the "comprehensive conservation plan" for ANWR. The original plan was signed into effect in 1988, and the service says it's time to freshen it up.

Already, the service has conducted a scoping process, which generated more than 94,000 comments from individuals and organizations.

Out of that has come the new draft comprehensive conservation plan, which the service announced on Aug. 12.

"The draft plan contains six alternatives for long-term management, ranging from the continuation of current practices to the designation of three geographic areas (including the Arctic Refuge coastal plain) for potential inclusion within the National Wilderness Preservation System, and the potential designation of four additional Wild and Scenic Rivers on the refuge," an agency press release said.

The draft plan does not identify a preferred alternative, saying all options remain under "active consideration."

But it appears that sentiment within the Fish and Wildlife Service favors establishing new wilderness areas within ANWR.

Located in the extreme northeast corner of Alaska, the remote refuge takes in 19.3 million acres — nearly the size of South Carolina. About 40 percent of ANWR already is designated wilderness.

The draft plan — specifically Appendix H, the "wilderness review" — indicates three huge new chunks of ANWR are "preliminarily recommended for wilderness designation."

These include the coastal plain at 1.6 million acres; a southern ANWR area known as the Porcupine Plateau at 4.4 million acres; and the western Brooks Range area at 5.7 million acres.

All told, practically all of ANWR would be wilderness if these three areas were designated as such, with only relatively small areas near villages remaining non-wilderness.

No oil, gas alternatives

The Fish and Wildlife Service is inviting public comments on the draft plan through Nov. 15. The agency plans to hold public hearings around the state, including one in Anchorage on Sept. 21 and another in Fairbanks on Oct. 19.

The plan and details on how to submit comments are online at http://arctic.fws.gov/ccp.htm.

The agency aims to issue its "record of decision" by the end of 2012.

"If the final plan recommends additional Wilderness and/or Wild and Scenic River designations, the recommendation(s) would require approval by the Director of the Fish and Wildlife Service, the Secretary of the Interior, and the President," the agency press release said. "The President would then submit the recommendation to Congress, which alone has the authority to make final decisions on any proposed Wilderness or Wild and Scenic River designations."

Although comments received during the scoping process overwhelmingly concerned the coastal plain and the question of oil and gas activity, the Fish and Wildlife Service chose not to include plan alternatives to allow oil and gas leasing or 3-D seismic shoots in ANWR, which the U.S. Geological Survey in 1999 estimated could hold several billion barrels of oil.

The governor's office criticized the service for excluding industry alternatives, calling that decision "inconsistent with existing federal law."

But nothing in the statutory mission of the National Wildlife Refuge System requires the service to consider or propose development scenarios for oil and gas or other natural resources, the agency said. Anyway, the service added, Congress has reserved the authority to make final decisions on oil and gas development in ANWR.

As for criticism that its wilderness review violates the "no more" clauses in ANILCA, the service argues to the contrary, saying the review is just a "tool" to make sure ANWR is being managed right.

—WESLEY LOY

Contact Wesley Loy at wloy@petroleumnews.com

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BULLET LINE

the past, telling legislators that if the state is going to spend billions for higher-cost natural gas than the state would get from a big line, it needs to consider putting that money into the big line. An in-state line built as a spur line just from Fairbanks to Southcentral is much more affordable, he said.

Persily said he was concerned about the Alaska public, which appears to believe the big pipeline won't happen and is turning to other less attractive options.

Getting gas to Southcentral drove the in-state gas pipeline project, but with the revised project schedule from AGDC now shows first gas in late 2018.

Persily advised against letting Cook Inlet drive the decision, because, he said, you can't get the gas there in time.

Fairbanks load issue

Harold Heinze, CEO of the Alaska Natural Gas Development Authority, said he questioned the Fairbanks volumes attributed to the line, some 60 million cubic feet a day, based on the recent announcement that Golden Valley Electric Association and Flint Hills were looking at trucking LNG from the North Slope.

He said it would be hard for the bullet line to compete with that. He noted that 500 million cubic feet a day requires an anchor tenant, 250 million has been discussed as the baseline, but said that could drop to 167 million cubic feet a day with LNG trucked to Fairbanks, substantially raising the tariff, with Alaska consumers paying that cost.

Wagoner asked why the GVEA-Flint Hills proposal would benefit Fairbanks beyond those entities and Heinze said the Fairbanks gas market is primarily GVEA and Flint Hills, actually located in North Pole, and close to the next biggest users, the military. If needed, he said, it would be easy enough to make LNG deliveries at some point in downtown Fairbanks. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● NATURAL GAS

Guide to Alaska natural gas projects

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Ideas for moving Prudhoe Bay's natural gas bounty off Alaska's North Slope are as plentiful as cottonwood seed in the June air.

Some are modest: Truck small amounts of gas to Fairbanks consumers.

Some are epic: Pipe massive amounts to Lower 48 consumers — the most expensive North American private-sector construction project ever.

Some are pinned to visions of an Alaska energy utopia, where gas for local use is plentiful and relatively cheap, the oil industry reawakens to develop new fields by the dozen, the state treasury overflows with wealth, and new industries sprout from the earth like wild lupine.

Some are backed by tens or even hundreds of millions of dollars to design, engineer and otherwise prepare for construction. These include the major pipeline through Canada and a much more modest pipeline to Southcentral Alaska.

Some are little more than a concept looking to catch on.

The great North Slope oil discoveries of the 1960s and 1970s also found an estimated 35 trillion cubic feet of natural gas - one and a half times the entire volume of U.S. production last year. The U.S. Geological Survey estimates an additional 221 trillion cubic feet await discovery in Alaska's Arctic, onshore and offshore. If only an economically viable way could be found to move the gas to consumers.

Below we summarize several proposals — big and small — for transporting natural gas from Alaska's North Slope.

Pipeline to Alberta

This involves an approximately 1,700-mile, 48-inch buried pipeline from the Prudhoe Bay field on Alaska's North Slope to the British Columbia-Alberta border in Canada. From there, the gas could flow to the Lower 48 via an extensive network of existing pipelines.

The gas line would parallel the trans-Alaska oil pipeline from Prudhoe Bay to Delta Junction, then continue into Canada roughly parallel to the Alaska Highway.

The pipeline would move up to 4.5 billion cubic feet of gas per day.

The project includes a 58-mile pipeline to Prudhoe Bay from the Point Thomson gas field.

Sponsor

TransCanada and ExxonMobil, also known as the Alaska Pipeline Project.

Estimated cost

$32 billion to $41 billion (2009 dollars).

The cost includes a $12 billion gas treatment plant at the Prudhoe Bay field to remove water, carbon dioxide and other impurities from the gas, then compress the raw gas before it enters the pipeline.

Gas for Alaskans

The pipeline would provide at least five points in Alaska from which spur lines could be built to provide gas to Alaskans. The APP project involves only providing gas takeoff points, not construction of the spur lines, which would be up to the state, utilities or private companies.

The great North Slope oil discoveries of the 1960s and 1970s also found an estimated 35 trillion cubic feet of natural gas - one and a half times the entire volume of U.S. production last year. The U.S. Geological Survey estimates an additional 221 trillion cubic feet await discovery in Alaska's Arctic, onshore and offshore. If only an economically viable way could be found to move the gas to consumers

Status

In the development stage. The project sponsor is refining details — from the physical pipeline to the exact route — and seeking customers to ship gas through the line.

The Alaska Pipeline Project spent an estimated $303 million from the project onset through June 2011 and plans to spend $209 million more during the following 12 months. Under the Alaska Gasline Inducement Act of 2007, the state plans to reimburse the sponsor for up to $500 million of its estimated $717 million in pre-construction costs.

Besides refining the project's design and engineering, they are gathering volumes of data on fish, wildlife, soils, vegetation, cultural sites, air quality and other information that can be used for the environmental impact statement the Federal Energy Regulatory Commission will prepare. The sponsor plans to apply to FERC in October 2012 for a certificate to construct and operate the pipeline. FERC's review is expected to take about two years.

The sponsor held an "open season" in 2010 at which it solicited pipeline customers. Alaska Pipeline Project officials said they are negotiating with major companies that bid significant volumes.

The sponsor needs commitments for much of its pipeline's capacity to obtain construction financing.

Proposed timeline

October 2012 — Project sponsor plans to apply to the Federal Energy Regulatory Commission for a certificate of public convenience and necessity allowing pipeline construction and operation.

2012-2014 — FERC reviews the application and produces an environmental impact statement

2014 — U.S. and Canadian approvals issued

2015-2020 — Construction and commissioning

2020 — First gas flows

Pluses

• Short-term economic boost to Alaska during construction. Estimated 7,000 jobs during peak construction.

• Likely long-term economic boost as billions of dollars in revenue flows to state treasury, the Alaska Permanent Fund and local governments along the pipeline route.

• Outlet for natural gas now stranded on Alaska's North Slope should spur oil and gas exploration, finding new crude for the trans-Alaska oil pipeline and extra gas for a gas pipeline.

• With a spur line, consumers in Alaska's Railbelt could be assured of an affordable supply of gas for decades. The project likely is the cheapest source of new natural gas to supplement Cook Inlet supplies in Southcentral Alaska. For the Fairbanks area, relatively inexpensive gas would ease high energy prices for heating and power generation.

• The project might give rise to two industries in Southcentral Alaska, one that exports natural gas liquids and another that exports liquefied natural gas.

• About half of the construction cost could be backed by federal loan guarantees; federal tax breaks are available for pipeline and gas treatment plant.

Minuses

• High cost makes project risky for lenders that would supply construction financing.

• Requires major gas shippers - likely the North Slope producers - to commit to using the pipeline for at least 20 years.

• Not knowing what natural gas market prices will be over that long time horizon makes the project extremely risky for gas shippers. Low prices could shrink or eliminate their profits.

• North Slope producers want state of Alaska to set stable fiscal terms for gas production and the pipeline.

• Fairbanks area energy costs remain relatively high until 2020 or later, when natural gas is flowing. Pipeline might not be running before Southcentral Alaska needs supplemental source of natural gas.

Pipeline to Southcentral

A 737-mile, 24-inch buried pipeline from the Prudhoe Bay field on Alaska's North Slope to the Big Lake area of Southcentral Alaska. From there, the gas could flow to consumers, utilities and other industry via the local distribution pipelines of ENSTAR Natural Gas Co. Pipeline also would supply Fairbanks area.

The pipeline would parallel the trans-Alaska oil pipeline from Prudhoe Bay to just north of Fairbanks, then continue south to Big Lake, roughly parallel to the Parks Highway.

The pipeline would move up to 500 million cubic feet of gas per day. The project also is known as the "bullet line," the in-state line and the Alaska Stand Alone Pipeline, or ASAP.

Sponsor

Alaska Gasline Development Corp., a state agency the Legislature created in 2010.

Estimated cost

$5.3 billion to $9.8 billion (2011 dollars). Sponsor is using midpoint of $7.52 billion as a working number.

The cost includes a $1.84 billion gas treatment plant at the Prudhoe Bay field to remove water, carbon dioxide and other impurities from the gas, then compress the raw gas before it enters the pipeline.

Project cost does not include a separate 35-mile spur line as well as local gas distribution network needed for Fairbanks. A local gas pipeline network

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already exists in Southcentral.

Gas for Alaskans

Gas for Alaskans was the main idea for this project when the state Legislature funded a feasibility study in 2010.

Status

Project is in its very early stages. Feasibility study issued in July 2011 provided a preliminary plan, and the sponsor recommends the state spend $370 million to firm up the design, cost estimates and engineering, acquire permits and seek customers that would ship gas through the pipeline.

Proposed timeline

2011-2015 — Project sponsor sharpens engineering and cost estimate, obtains permits, solicits customers

2015-2018 — Construction and commissioning

2018-2019 — First gas flows

Pluses

• Short-term economic boost to Alaska during construction of multibillion-dollar project.

• The project could deliver gas to Fairbanks and Southcentral two years sooner than the larger pipeline to Alberta.

• Consumers in Alaska's Railbelt could be assured of an affordable supply of gas for decades. In Southcentral Alaska, the gas could supplement Cook Inlet supplies used for heating and power generation. Delivering natural gas to Fairbanks could greatly lower that community's high cost of energy.

• The project might give rise to new industries in Southcentral Alaska, one that exports natural gas liquids and another that exports liquefied natural gas.

Minuses

• Likely requires state to issue billions of dollars in revenue bonds.

• The cost estimate is soft. A much higher cost than the midpoint $7.52 billion estimate would alter the project economics.

• Requires major gas shippers to make long-term commitments to use the pipeline.

• The project would produce far less new state revenue than the Alberta pipeline due to the small volume of gas moved and the state's tax structure.

• Requires the state to bear all of the pre-construction cost because no private developer will do so.

• Project sponsor wants state law to exempt the pipeline's shipping charges, or tariffs, from regulation.

• The cost of gas to Alaskans would be higher than gas from the pipeline to Alberta.

• The project would not spark as much Arctic oil and gas exploration as the bigger pipeline.

• The project relies on a chain of assumptions about demand for gas that must come true to make the gas as affordable to Alaskans as predicted. These assumptions include:

1) A revived liquefied natural gas export plant will take almost half of the daily gas flow.

2) A separate business will invest nearly $1 billion to build a plant in the Matanuska-Susitna Borough to take propane and butane from the gas stream, process them and find buyers for them inside or outside Alaska.

3) A major mine, such as the Donlin gold prospect in Western Alaska, will start up by 2019 and consume 6 percent of the daily gas flow.

4) A utility or utilities will build a spur line and a local gas distribution pipeline network in Fairbanks by the time the pipeline from Prudhoe Bay is ready.

5) Cook Inlet gas production will fall to such a point that power plants and the local gas utility in Southcentral Alaska will consume about 20 percent of the pipeline's gas.

Pipeline to Valdez

An 803-mile, 48-inch buried pipeline from the Prudhoe Bay field on Alaska's North Slope to Valdez. From there, the gas would be chilled to minus 260 degrees to create liquefied natural gas, or LNG, that can be shipped on special tankers to markets worldwide.

The pipeline would parallel the trans-Alaska oil pipeline.

The pipeline would move up to 3 billion cubic feet of gas per day, with Alaskans using some and 2.8 billion arriving in Valdez for export.

Sponsors

Two separate groups have proposed similar concepts for a Valdez pipeline.

TransCanada and ExxonMobil, which are pursuing the pipeline from Alaska to Alberta, also asked potential gas shippers in 2010 if they prefer a Valdez route but have not disclosed the results. Their concept calls for someone else to build the multibillion-dollar gas liquefaction plant and tanker port in Valdez and procure tankers. TransCanada and ExxonMobil in April 2011 indicated they are focused on the Alberta pipeline project rather than Valdez. (See "Status" below.)

The Alaska Gasline Port Authority, founded in 1999, also has proposed a Valdez LNG project. The port authority is a joint venture of the Fairbanks North Star Borough and Valdez, two local governments along the pipeline route. The port authority has no recent cost estimates for the project.

Estimated cost

$43 billion to $49 billion?

Pipeline: $20 billion to $26 billion (2009 dollars). This TransCanada/Exxon estimate includes $11 billion for the Prudhoe Bay plant to remove water, carbon dioxide and other impurities from the gas, then compress it before it enters the pipeline.

LNG plant and Valdez port: $23 billion? This figure is derived from a July 2011 study for the port authority. Tankers would cost $200 million per ship, the study said.

A 2008 state of Alaska study estimated the liquefaction plant and port would cost $10.8 billion to $17.6 billion.

Gas for Alaskans

The TransCanada/Exxon pipeline would provide at least five points in Alaska from which spur lines could be built to provide gas to Alaskans. This project involves only providing gas take-off points, not building the spur lines, which would be up to the state, utilities or private companies.

The port authority says gas could be taken from the pipeline at Fairbanks and that a spur line from Glennallen could provide gas to Southcentral Alaska.

Status

This project appears to be dormant.

The TransCanada/ExxonMobil team in April 2011 told the Federal Energy Regulatory Commission that it is focused on design, engineering and regulatory approval for the pipeline to Alberta, not Valdez. FERC in August 2011 said it has received little information on the Valdez proposal and has no plans to conduct an environmental review, which is needed to move project ahead.

The port authority continues to tout the LNG export idea in speeches, op-ed columns and interviews.

Pluses

• Short-term economic boost to Alaska during construction.

• With the right project economics, long-term boost as billions of dollars in revenue flows to state treasury, the Alaska Permanent Fund and local governments along the pipeline route.

• Valdez gets new industry based on LNG export.

• Outlet for natural gas now stranded on Alaska's North Slope should spur oil and gas exploration there.

• Relatively inexpensive gas made available for heating and power generation in the Fairbanks area.

• For Southcentral Alaska, project with spur line likely an affordable source of new natural gas to supplement Cook Inlet supplies.

Minuses

• Most expensive option. High cost makes project risky for lenders that would supply construction financing.

• Federal loan guarantees available only for pipeline project that delivers gas to the Lower 48, not projects that would export gas. Lack of federal backing would raise project costs.

• Buyers needed immediately for huge output from LNG plant, with little ramping up of project over time.

• Shippers must commit gas to pipeline for 20-plus years and find long-term buy-

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ers for the LNG in a Pacific LNG market that other exporters are targeting.

• Fairbanks area energy costs remain relatively high until pipeline is running.

• Southcentral Alaska could need supplemental source of natural gas before pipeline is finished.

Cook Inlet gas exploration

In June 2011, the U.S. Geological Survey estimated the Cook Inlet region still holds an estimated 19 trillion cubic feet of natural gas that could be produced using current technology.

That's more than double the total Cook Inlet gas production over the past 50 years. But how much of the gas could be produced profitably with current technology likely is a much smaller number, possibly as little as 10 percent.

Separately in June, the Alaska Division of Oil and Gas estimated that Cook Inlet alone could continue to profitably supply all of the region's natural gas needs until 2018-2020, at which time supplemental supplies would be needed. The study said the gas industry must continue investing in the Inlet for this prediction to hold.

The state Legislature over several years has created a package of incentives to boost Cook Inlet gas production.

A key incentive offers up to $25 million in tax credits for the first exploration well drilled from a jack-up rig, up to $22.5 million for the second well drilled by a different company and up to $20 million for a third well by a third producer.

At least two companies are pursuing those incentives. Escopeta Oil moved a jack-up rig to Cook Inlet in August 2011 and hopes to start drilling in the fall. Buccaneer Energy hopes to bring in a jack-up rig, partly financed with state money, in 2012.

Another state incentive provides a 20 percent to 65 percent tax credit for oil and gas exploration or development capital spending, in Cook Inlet or elsewhere in Alaska.

Importing LNG

In 2011, three Anchorage utilities joined to consider the idea of importing liquefied natural gas to Southcentral Alaska.

ENSTAR Natural Gas Co. supplies gas for residential and business furnaces, and Chugach Electric Association and Municipal Light & Power burn gas to make electricity.

They estimate Cook Inlet fields might not produce enough gas by 2014 to fulfill their needs. The supply gap would start small but grow to as much as 140 million cubic feet a day on average by 2020, they told state utility regulators in June 2011. Their idea is that an import project should be scalable so that more gas could come in as the utilities' needs grow.

Since then, the USGS and Alaska Division of Oil and Gas have issued rosier projections of Cook Inlet's potential gas supply.

The utilities continue to explore the cost, design, location, volumes needed, potential suppliers, regulatory issues and other aspects of opening an LNG import plant. While the USGS and state say there's a high probability that Cook Inlet's gas prospects are better than previously thought, that's short of the certainty of supply the utilities need.

Gas to Fairbanks by truck or pipe

Three ideas have been floated for getting North Slope natural gas to the Fairbanks area, where energy costs are much higher than in Southcentral Alaska.

LNG trucked to Golden Valley Electric and the Flint Hills refinery

In August 2011, Golden Valley Electric Association and Flint Hills Resources announced a project to buy North Slope gas, superchill it to make LNG and truck it about 500 miles to North Pole.

They pegged the cost at $180 million, including an LNG plant, about 40 trucks, storage, plus a plant to regasify the LNG in North Pole. Startup would be early 2014. They said engineering has begun.

Both companies said they would use the gas - about 20 million cubic feet a day on average - to replace more expensive fuels. Golden Valley would burn the gas at its North Pole power plant. Flint Hills would burn gas at its North Pole oil refinery.

Fairbanks community leaders said some extra gas could be sold elsewhere in the Fairbanks area.

Trucked LNG by Fairbanks Natural Gas LLC

Fairbanks Natural Gas also has a plan to truck North Slope LNG to Fairbanks.

The company, a subsidiary of Minnesota-based Pentex Alaska Natural Gas, has been liquefying Cook Inlet gas and trucking it to Fairbanks since 1998. Last year it posted a $3 million profit on $16.1 million in gas operating revenue, according to filings with state utility regulators.

Fairbanks Natural Gas has contracted for Cook Inlet gas supplies into mid-2013. But with overall Cook Inlet output falling, several years ago a Fairbanks Natural Gas affiliate, Polar LNG, contracted with ExxonMobil to buy gas from the oil company's Prudhoe Bay production. In 2009, it leased state land near Prudhoe Bay as a site for an LNG plant.

The LNG plant hasn't been built yet. With Golden Valley and Flint Hills pursuing their own trucked LNG idea, Fairbanks Natural Gas may have lost two potential major customers. It's unclear what happens next to its trucked LNG project.

In August 2011, the Alaska Gasline Port Authority dropped its idea to buy Fairbanks Natural Gas to take over its trucked North Slope LNG proposal.

Piped natural gas to Fairbanks

Fairbanks Pipeline Co. started in 2010 and is proposing a Prudhoe Bay-to-North Pole pipeline to deliver natural gas to Interior Alaska customers. Fairbanks Pipeline is owned by Energia Cura, a Fairbanks energy consulting and service business.

The company said it is targeting Golden Valley Electric, military bases, trans-Alaska pipeline pump stations and mines, as well as Fairbanks Natural Gas, the small local gas utility. It has estimated the 514-mile, 12-inch buried pipeline would cost $709 million to $716 million, but the company now believes the cost will be lower after hearing from steel mills that could supply the pipe. The route would follow state highways. The Energia owners are funding development costs, the company website says. They hope others, including the state, possibly through its Permanent Fund savings account, become owners.

Fairbanks Pipeline held an open season soliciting customer interest during the third-quarter of 2010 and said it got non-binding interest for 32 million cubic feet of gas a day as of 2014, ramping up to 52 million in 2019. Gas buyers would pay $9.66 per thousand cubic feet, under the plan. The company also is considering a larger, 18-inch pipeline project that, besides serving Interior Alaska markets, also would deliver about 200 million cubic feet a day to Southcentral. ●

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/guide-to-Alaska-natural-gas-projects.

Petroleum news

Oil Patch Bits

Lynden chosen a Top 100 3PL provider for 2011

The Lynden family of companies said Aug. 9 that it was chosen as one of the Top 100 third-party logistics service providers by editors of Inbound Logistics magazine. Editors selected the companies from hundreds of contenders, choosing only those that offer the diverse operational capabilities and experience to meet readers' unique supply chain and logistics needs.

Inbound Logistics' Top 100 3PL Providers list serves as a qualitative assessment of service providers. Each year, editors solicit questionnaires from more than 400 3PLs, detailing the services they provide and their areas of expertise. The magazine also polls more than 5,000 3PL users with a similar series of questions to provide a counter-perspective of the forces shaping the industry

"Whatever the company size — from Fortune 500 to small businesses — world-class logistics performance is crucial. It is impressive to see Lynden providing the kinds of solutions that companies large and small rely on to solve the tactical logistics issues of serving customers better, faster and more efficiently," said Felicia Stratton, editor of Inbound Logistics magazine.

The Lynden family of companies' combined capabilities include: truckload and less-than-truckload freight to Alaska, scheduled and charter barges, rail barges, intermodal bulk chemical hauls, scheduled and chartered air freighters, domestic and international shipping via air and ocean forwarding, customs brokerage, trade show shipping, remote site construction, sanitary bulk commodities hauling and multi-modal logistics.

Hawk wins Governor's Safety Award of Excellence

Hawk Consultants said April 6 that the Alaska Safety Advisory Council announced that it has won the Governor's Safety Award of Excellence for 2011. Hawk was presented the award by Commissioner of Labor Click Bishop at the 30th Annual Governor's Safety and Health Conference Awards Luncheon on March 24 in Anchorage.

The award was in recognition of Hawk's milestone achievement of 1 million hours worked without an injury or lost-time accident. Hawk has worked in the Alaska oil patch since 1985 and has never had a lost time accident.

This remarkable achievement is a tribute to the quality and dedication of Hawk's employees and the support of its clients and a strong belief in the conference motto "Safety Isn't Expensive — It's Priceless".

Hawk Consultants LLC is an Alaskan-owned firm specializing in project management services supporting client organizations with people and resources to deliver projects safely, on time, on budget and without adverse environmental impact. For more information visit

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YOUNG Q&A

Senate probably won't pass it because of Harry Reid of all people. If Obama were smart, he'd come out in favor of it. We could put 2 million barrels in that pipeline, and it would drop the price of gasoline dramatically because the other countries would see we are serious about this, and we can get this economy back on a road to recovery. I'll pass it out of the House, then it will get over to the Senate. If we control the Senate next session, we'll probably get it passed and hopefully we'll have a new president and someone will see the logic of opening ANWR. It is not the pristine area they are talking about. Never has been; never will be. We have an infrastructure in place that needs more oil. It isn't (Alaska's) oil. It will be federal oil, so we won't get much money out of it. It's important to create the jobs to keep the pipeline going. I do think we will eventually get it done. I said I want to live long enough to get it done. In fact I told (U.S. Rep. Ed) Markey, if we get ANWR opened up, I might quit. He damn near took me up on it, but I'm going to get ANWR done before I get out of here.

Petroleum News: Moving offshore, what are your thoughts on Shell's efforts to get permits to begin drilling and some of the hurdles they've encountered?

Young: My biggest concern is they might drop out. They've got $5 billion out there invested, starting with $2.5 billion on the lease bid. This is all gobbledygook. One thing that's bad about the president. He says I'm all for leases on the Beaufort; I'm all for leases on the Chukchi Sea. The reality is that doesn't solve the problem. If the agency doesn't provide the permits, we aren't going anywhere. I'd be dog gone reluctant to bid on a lease if I didn't have some assurance that I could actually drill the area. I've said all along in the new ANWR bill, we are going to put a provision, if we open it up, it will be drilled — like we did the pipeline. That's the reason we got the pipeline built. It was my provision that said there will be no lawsuits.

Petroleum News: Speaking of pipeline, what are your concerns about throughput in the pipeline?

Young: I have big concerns. Everybody knows it's declining. It's heavier oil. It's more waxy in content as everybody knows and that makes it more difficult to keep the line moving smoothly. If it weren't for the refinery in North Pole, the oil might not be warm enough to go all the way to Valdez. We have to increase that. I think we have to look at new ways to do it or get the Chukchi open. The goal of the environmental community is to make sure the pipeline finally gets to 300,000 barrels and they have to shut down and can't run it, and it has to be pulled up. This is the Pelosi, Waxman, Schumer, no fossil fuels philosophy. I'm a big believer we will get that pipeline moving. If we don't it will be a bigger problem, not only financially to the state, but the bigger problem is to the rest of the nation, which is really scary. We still import 72 percent of our oil, yet we have a tremendous amount of oil in the north, and we have a tremendous amount of oil in other areas such as off the coasts of California, Virginia and Florida. We just have lacked the will to do it because it wasn't popular. Look at the battle of the (Alberta to Texas) Keystone pipeline, which is still not over. It's well and good and I would support it. It's a still a foreign oil source. Now they

> *"We have become over governed. We are over regulated. It's not just federal. The state is equally as bad."* **—Congressman Don Young, R-Alaska**

are better neighbors but we should be using our own oil; instead, we are still going to pay $100 a barrel.

Petroleum News: Are you OK with the pipeline coming into this country?

Young: Oh, yeah I'm fine with it. We get more oil from Canada than we do from Venezuela. People don't quite know that but we do. At least they are friendly neighbors, but still, why are we buying from a friendly neighbor when we can be producing our own? That's the thing I don't understand. To me that's not being very smart. It's better buying from them than having it shipped in from Kuwait and Iran and Libya.

Petroleum News: There have been issues with pipelines the last five years. There were leaks on the North Slope; Enbridge had a leak in Michigan; Exxon had one in a Montana river. Are you concerned about pipeline integrity?

Young: I have concerns about transportation of any form. None of it is fail-safe. There is no other way to move oil. The biggest way is to make sure it's kept up. Remember this pipeline is 35 years old. The one in Montana, who in the world would have thought that would have flooded? The one in Michigan, that's another old system. Anybody who can show me another way to bring oil and gas in years old, I'm listening.

Petroleum News: If pipelines aren't maintained, does it make it more difficult for you in D.C?

Young: The money being spent is in maintenance; it's not being spent in development. It's like trying to get rich by using funny money. You have to dig and be developing new wells.

They said they saw two rigs leaving the Port of Seattle and going to Alaska. In the first place they didn't check it out. Second place, they were probably going up as those rigs they were replacing have been worn out.

So the money being spent is on maintenance. That's great for work now, but it doesn't increases the flow of oil. Then it decreases over time and that's a big problem.

Petroleum News: Do you still believe there can be a market for a large-diameter gas line?

Young: No. No one is going to invest what I expect to be a $40 billion project and bring gas down to a market that is already saturated. There won't be a return on the money. I always said that would be a challenge. Frank Murkowski missed that open window and he told us that. If we had that agreement then (2005), we would have had a pipeline started. We lost that. I still insist we've got to look at the possibility of export because there will be a use for it in China and Japan. The state itself has got some real challenges. Whether we find some more gas in Cook Inlet or not, I don't know. We've got the rig up there, but it will relieve the pressure on the Railbelt. But Fairbanks is dying because of the high cost of energy. No one can expand stores. Those are the questions we are going to be faced with. Either we build a bullet line and bring it into Fairbanks, then Anchorage and down, or we build a larger line at least as far as Delta, maybe to Fairbanks, so later on if there is a market in the Lower 48, then we can take into the Midwest. But that's not going to happen for another 40 or 50 years. You know I'm paying $7.50 for heating oil in Fort Yukon right now. It's something you have to have. There's no doubt about that. We've got a lot of opportunities right now, if we would just do it. The other solution would be if you don't build a gas line, is Susitna Dam, which I have seen the Legislature and governor attempt to do. That might be cheaper than building a pipeline. The gas is there. We know it's there. We've got the energy; we just don't have the will or the desire to replace it. I think that's what we have to do.

Petroleum News: Is it up to the state Legislature to make it work, the industry or a combination?

Young: I don't know whether anybody is going to the industry to say would you be interested in a tidewater pipeline. If they said yes, then, that's not a bad idea. I think it would be a good idea. The state can be partners, but I don't particularly think the state should own it or manage it. Old man (Roy) Huffington at Huffington Oil he told me once 'don't ever let the government ever get involved in the industry because eventually it will corrupt the government.' I think we've seen that in places like Venezuela. The government doesn't police itself. The private industry can be policed by the people.

Eighty-five percent of Alaska would benefit. That's very crucial. Southeast would not, so we would build up those hydro sites. Then you would have export to finance the line and make sure it's not so expensive. That's one reason you can't build a big line for the state of Alaska. We don't have the market. So I think if somebody would go and ask them to see if they are interested in building a gas line, you might be surprised. ●

Contact Steve Quinn at squinnwrite@gmail.com

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www.hawkpros.com.

The Alliance calls for 2011 board nominations

The Alliance board and elections committee said Aug. 15 that it is seeking members to serve on the Alliance board of directors. There are seven three-year terms available in the fiscal year 2012 elections. Election results will be announced at the annual meeting on Sept. 29. Newly elected members will begin serving their terms Oct. 1.

Alliance directors are leaders in the oil, gas and mineral resource industries. They are focused on improving the business climate for contractors by communicating with legislators and the administration in Juneau, serving on committees and participating in and supporting Alliance events throughout the year. These events are prime networking opportunities for all members of the Alliance.

Board members review industry issues, voice Alliance positions and develop strategies to improve and empower our organization. Directors may serve a maximum of two consecutive three-year terms.

If you are interested in running for a seat on the Alliance board of directors, please forward a written statement of candidacy to the Alliance office. Nominees must confirm their intent to run for a seat on the board. This may be provided in a letter format. Include a biography; a brief summary of employment; involvement in industry and/or business-related organizations and other pertinent information; and photograph, electronic headshot preferred. Nomination must reach The Alliance office by Aug. 22. Email to rlogan@alaskaalliance.com.

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

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GAS LINE TALKS

by remarks Department of Natural Resources Commission Dan Sullivan made Aug. 15 that the state and ExxonMobil had reached agreement in principle on Point Thomson (see story on page 1.)

External factors, such as changes in gas supply and demand in North America and globally over the last three years, are outside of TransCanada's control, he said, as are gas-price forecasts, liquefied natural gas exports and the condition of financial and debt markets.

The shale gas impact

Asked by Sen. Bill Wielechowski if the development of shale gas in the Lower 48 has made the Alaska Pipeline Project uneconomic, Palmer said the North American gas supply is higher today and public gas price forecasts are lower than they were three years ago. It is one of the external factors where potential customers of the pipeline will have to decide their own view, he said.

But to date, "we haven't seen customers walking away from the table," because of shale production, Palmer said.

Resources co-chair Joe Paskvan asked what the impact would be on the Alaska project if shale gas were developed in China.

Palmer said the topic is highly speculative, but that in his view those looking at whether China will have a shale gas revolution, with timing and cost uncertain right now, will know more in two to five years.

Asian LNG is still tied to a crude oil price, but some Asian buyers coming to North America have indicated they are seeking North American prices, Palmer said, noting that if they are successful, that could break the linkage of LNG prices to oil.

China has a shortage of natural gas and is importing both via pipeline and LNG and a low-price domestic source would impact both where that country gets its gas and the price.

On commercial side

Palmer said the project has advanced significantly on the commercial side over the last three years.

TransCanada and ExxonMobil have gone beyond the commercial terms included in the license TransCanada obtained under the Alaska Gasline Inducement Act, AGIA.

And TransCanada aligned with ExxonMobil on the project — and has a standing offer to align with BP and ConocoPhillips, he said. That gets the project part way toward having the five partners TransCanada has said would be needed: the State of Alaska, TransCanada, ExxonMobil, BP and ConocoPhillips.

Global gas markets have become more competitive, Palmer said, and in the open season documents for the project the offer in the AGIA documents was enhanced by $500 million a year to customers, over the life of the project a $12.5 billion total reduction in tolls.

He said he couldn't identify further concessions made in the negotiations, but said the companies will make more concessions in trying to get over the finish line.

While customers would say you could go lower, Palmer said, from the perspective of a pipeline company there is a very competitive offer on the table.

Monies spent

Wielechowski asked how much money would be spent until issuance of the license. TransCanada is committed under AGIA to advance the project through receipt of a Federal Energy Regulatory Commission certificate of convenience and necessity, even in the absence of customers, one of the conditions the state extracted in exchange for its $500 million participation.

Palmer said if the project is unsuccessful at getting customers it will spend on the order of $700 million by 2014, $500 million of which would be reimbursed by the state.

If we have customers, we'd accelerate spending because we would be moving to put the line into service, he said.

Denali, the BP-ConocoPhillips sponsored proposal, folded in May, citing lack of customer support.

Palmer said he always thought TransCanada had the advantage in Canada, and also had the skill set to advance the project, a skill set which improved with the ExxonMobil alignment in June 2009.

No one ever thought two lines would be built, Palmer said: One had to go away or they had to combine.

Asked by Sen. Hollis French how three impediments to the project — Point Thomson, gas fiscals and long-term prices — should be ranked, Palmer said until the state and the producers have resolved their issues, it's hard to get people to focus on the third issue, whether the project is economic.

At low gas prices, the first two conditions, while necessary, may not be sufficient, Palmer said, but the producers are used to taking price risk, and they are not making the call today.

Asked by Rep. Kurt Olson when TransCanada would make the hard decision to continue or not, Palmer said that while TransCanada had assumed Point Thomson and gas fiscals would be resolved by the end of the open season, as long as there continues to be optimism that they will be resolved, "we'll let the game play out."

Sunk cost

Wielechowski was concerned that legislators had to make decisions about funding the AGIA project and the in-state line, ASAP, and pressed Palmer for more information.

Palmer said that under AGIA TransCanada has been able to share additional information with the administration, but said Wielechowski was asking for something that goes beyond what's in statute.

Sen. Bert Stedman, who co-chairs the Senate Finance Committee, said the state needs to come up with additional money in the next two fiscal years to meet its AGIA obligations.

He described the $500 million as a sunk cost, if TransCanada has customers and is moving ahead with the line or if it has no customers.

The only way we could not spend the funds is if the state and TransCanada come to a mutual agreement that the project isn't economic, which is not likely, Stedman said.

Building permit

Larry Persily, federal coordinator for Alaska Natural Gas Transportation Projects, told Senate Resources Aug. 17 that AGIA had been oversold and misunderstood. It was never going to get you a pipeline, he said: It's a path toward getting a building permit for a line — the engineering, design and permits.

The Stranded Gas Act, under which talks took place with North Slope producers under the Murkowski administration, scared Alaskans away from negotiations, Persily said. But the producers have to take risks including cost overruns and the price in the market and state fiscal terms must recognize the risks, he said.

He encouraged Alaskans to look at the gas line as a 50-year project which provides gas for Alaskans, state revenues and more exploration on the North Slope, which will find oil as well as gas.

Having a gas line makes Alaska more attractive, he said.

Persily also suggested that when the state does sit down with producers, some provisions of AGIA such as rolled-in tariffs would probably be back on the table.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

US drilling count up by 39 to 1,959

The number of rigs actively exploring for oil and natural gas in the U.S. increased by 39 the week ending Aug. 12 to 1,959.

Houston-based drilling product provider Baker Hughes Inc. reported that 1,055 rigs were exploring for oil and 896 for natural gas. Eight were listed as miscellaneous. A year ago this week the rig count stood at 1,640.

Of the major oil- and gas-producing states, Texas gained 20 rigs and North Dakota 14. Colorado was up seven, California up three, Pennsylvania two and Oklahoma one. Louisiana declined by five and Wyoming was down three. Alaska, Arkansas, New Mexico and West Virginia were unchanged.

The rig count peaked at 4,530 in 1981. A low of 488 was recorded in 1999.

—THE ASSOCIATED PRESS

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GAS CONTRACTS

Enstar plans to pull gas from the CINGSA facility during periods of high winter demand, starting in the winter of 2012-13, to ensure that gas can be flowed fast enough to meet gas consumers' peak needs.

Gas for storage

However, the primary purpose of the Buccaneer contract will be to ensure sufficient gas supplies to meet Enstar's contracted use of the CINGSA storage facility, Enstar spokesman John Sims told Petroleum News Aug. 15. Enstar plans to pull gas from the CINGSA facility during periods of high winter demand, starting in the winter of 2012-13, to ensure that gas can be flowed fast enough to meet gas consumers' peak needs.

According to Enstar's tariff filing, the Buccaneer contract for guaranteed gas supplies from 2012 involves pricing indexed to the New York Mercantile Exchange gas futures, but with a minimum gas price of $5.71 per thousand cubic feet between March and November of each year, and a minimum price of $7.06 per thousand cubic feet between December and February. The maximum price at any time of the year would be $10 per thousand cubic feet. These floor and ceiling prices would be adjusted for inflation, starting in 2012. Based on projections of Nymex futures, Enstar anticipates the weighted average cost of gas purchased under the contract to rise from $5.89 per thousand cubic feet in 2012 to $6.16 per thousand cubic feet in 2014.

The pricing terms appear similar to those in earlier Enstar supply contracts with Marathon, approved by RCA in May 2010, and with Anchor Point Energy, approved by RCA in November 2009. Those earlier contracts both had inflation-adjusted price floors and ceilings of $6.85 and $9.70 year round. Anchor Point Energy is selling gas from the Armstrong Cook Inlet-operated North Fork gas field in the southern Kenai Peninsula.

However, Sims said that based on a comparison of the price floors between March and November, the Buccaneer contract pricing should work out a bit lower than that for the Anchor Point Energy contract.

Up to 31.5 bcf

The Buccaneer contract requires the delivery of a total of 12 billion cubic feet of gas to Enstar, with an option to increase that total volume to 31.5 bcf, with these volumes likely taking until 2018 to deliver, Enstar says. The contract requires Buccaneer to complete the drilling of two new wells at Kenai Loop, one well by Nov. 1 this year and the other well by Nov. 1, 2013.

According to a Buccaneer press release, Buccaneer will initially deliver gas from Kenai Loop at the rate of 5 million cubic feet per day in 2012, with an option to increase that rate to 15 million cubic feet per day after six months, depending on progress with the drilling of new wells.

Although the Buccaneer contract for firm gas supplies will help fill a looming gap in Enstar's annual gas supply needs, Enstar's customers will still likely face supply shortfalls, starting at 5.9 bcf in 2013 and growing to 18.9 bcf in 2018, in the absence of further gas supply contracts, Enstar says. On the other hand, the storage of Buccaneer's gas in the CINGSA facility should stave off any shortfall in the rate of delivery of winter gas until 2018.

And Enstar presumably hopes that the recent startup of new Cook Inlet gas exploration will further bolster its supplies. The new contracts and recent enthusiasm by small independent gas explorers operating in the Cook Inlet basin appear to reflect the impact of incentives for gas exploration that the Alaska Legislature has enacted, Sims said.

Bidding system

Meantime, with insufficient gas under firm contract to meet potential delivery needs in the winter of 2011-12, before CINGSA comes online, Enstar will be operating its day-to-day bidding system, to try to fill any supply shortfalls as necessary.

None of the contractual arrangements for gas supplies through the bidding process guarantee to make gas available but do allow qualified gas producers to bid to deliver to Enstar any gas that they have available for immediate sale. Enstar's three new contracts add Buccaneer, Aurora Gas and Cook Inlet Energy to the list of qualified producers, thus increasing the likelihood of finding any necessary short-term supplies — Enstar already has contracted arrangements for the potential purchase of "non-firm" gas from Unocal, Marathon, ConocoPhillips and Anchor Point Energy. ●

Contact Alan Bailey at abailey@petroleumnews.com

EXPLORATION & PRODUCTION

US oil well celebrates 150th birthday

A tiny oil well in northwestern Pennsylvania has celebrated its 150th birthday as the world's oldest continually producing well.

The Titusville Herald reports dozens of people gathered in Rouseville, about 70 miles north of Pittsburgh, to mark the occasion at McClintock Well No. 1 on Aug. 16.

Officials at the nearby Drake Well Museum say the former Quaker State oil company donated the well to the museum in 1955.

The well was drilled on Aug. 16, 1861, and produced about 175 barrels a day before slowing to 50 barrels some years later. The well still produces about 40 barrels of oil a year, which goes to the American Refining Group in Bradford.

The National Park Service declared the well an American Treasure in 1999.

—THE ASSOCIATED PRESS

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PATH TO THE GULF

border.

Daniel said that although a date has not yet been set for an open season, the Monarch proposal will "come to a head in a matter of months" because of the pressure to start moving crude from the Alberta oil sands and the Bakken play in North Dakota and Saskatchewan to U.S. Gulf Coast refineries.

He said many prospective customers are "coming close" to endorsing Monarch.

Saturation point fast approaching

Enbridge Chief Financial Officer Richard Bird said there is now so much light crude coming out of western North America that the saturation point is fast approaching in U.S. Midwest markets, where refineries are being converted to handle greater volumes of heavy crude.

The Cushing bottleneck and high price differentials between West Texas Intermediate and North Sea Brent has climbed as high as US$25 per barrel and is costing Canadian producers as much as C$50 million a day because of their reliance on a single export market, prompting the clamor for an alternative route to Asia.

Monarch, although only one-third of the 1.1 million bpd capacity on the combined Keystone pipelines, would offer some shorter-term relief along with access to the PADD III region, which encompasses the Texas refining hub, where Canadian imports currently amount to less than 3 percent of the volumes.

But PADD III is a natural outlet for Canadian heavy crude, which compares favorably with the shrinking supplies of Mexican Maya and Venezuela Orinoco crudes, as well as Saudi medium.

Others in race to Gulf

The race to the Gulf Coast is not confined to the two Canadian companies.

Enterprise Products Partners and Energy Transfer Partners are proposing a 450,000 bpd line from Cushing to Houston by 2012.

Enbridge is also exploring other options to deliver more light crude to Eastern Canada and the U.S.

They include greater access to Minnesota and the Chicago area to take advantage of increased heavy crude cracking capacity and the reversal of Enbridge's existing 240,000 bpd Line 9 from Montreal to Sarnia, Ontario, which Daniel said "has very good prospectivity."

Enbridge enters the competition armed with a new tolling agreement for the Canadian portion of its mainline and an international joint tariff for cross-border shipments, which Daniel said offers mainline shippers a stable and competitive long-term toll.

He is not concerned about the flurry of interest in the use of railroads to transport crude, including announcements by Oklahoma-based Musket to increase its rail capacity from North Dakota's Bakken play to 70,000-80,000 bpd from 10,000-16,000 bpd and by Plains All American that it plans to double capacity at its crude-by-rail terminals in Illinois and Louisiana.

Daniel said rail offers "relatively low-cost, early entry into the transportation business, but long-term we can definitely beat rail in terms of tolls and reliability."

"Even though these rail facilities might be put in place initially, they're just a precursor of even more pipeline opportunities for use out of the Canadian and U.S. Bakken," he said. Bakken production is forecast by the U.S. Energy Information Administration to exceed 1 million bpd within a few years, enough to almost displace current Saudi imports. ●

Contact Gary Park through publisher@petroleumnews.com

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FIELD FIGHT

field is coming to a close, heading off what easily could be years more litigation between DNR and the major Point Thomson stakeholders. Besides ExxonMobil the major players include BP, Chevron and ConocoPhillips.

Alaska economic development boosters are anxious to see the legal cloud lifted from Point Thomson, as it contains roughly a quarter of the North Slope's 35 trillion cubic feet of natural gas. Many believe that all the gas, including the Point Thomson reserves, are needed to make a North Slope gas pipeline a viable project.

A settlement also conjures intriguing possibilities for how the field's considerable endowment of oil and other hydrocarbon liquids might be exploited. Full-blown development of these resources could generate a boomlet of industry activity on the Slope.

Private briefing offered

DNR began taking firm steps to break up the Point Thomson unit and reclaim the state-owned acreage in 2005, during the administration of Gov. Frank Murkowski.

Sullivan noted that, while Point Thomson gas is considered important for a North Slope gas pipeline, the field also is rich in petroleum liquids, and production of those liquids could help stem the oil throughput decline on TAPS, the trans-Alaska pipeline system.

The state's beef is the lack of any production to date from Point Thomson, despite its discovery decades ago in the late 1970s.

The field is located along the Beaufort Sea coast next to the Arctic National Wildlife Refuge.

The oil companies went to court to block the state's effort to break up the unit, and today the case rests before the Alaska Supreme Court.

In recent weeks, DNR and the oil companies have filed heavy legal briefs, suggesting that no out-of-court settlement was near.

Yet the two sides have been negotiating for a year or more, with Gov. Sean Parnell and ExxonMobil executives stating publicly they wanted to settle the dispute.

Sullivan offered to brief legislators on the settlement terms "in a confidential setting."

"Thank you, commissioner, I think that we would probably seek to take advantage of that offer because I think ... it is a material step forward," replied Sen. Joe Paskvan, a Fairbanks Democrat and committee co-chairman.

Sen. Hollis French, D-Anchorage, asked Sullivan whether it was "fair to say that the state and Exxon are through negotiating and that negotiations that are taking place now are between Exxon and its partners. In other words, we made sort of our last best offer."

Sullivan: "I think it's fair to say."

During the court proceedings, some friction emerged among the Point Thomson working interest owners, with Chevron, BP and ConocoPhillips complaining that they had been shut out of the negotiations between the state and ExxonMobil.

Deal timing unclear

ExxonMobil was measured in its response to Sullivan's remarks. The company provided this statement via e-mail to Petroleum News and other media outlets:

"We're aware of the State's testimony on August 15, 2011 at the legislative committee hearings. We remain committed to working with Governor Parnell's administration and the other working interest owners to finalize a settlement.

"Settling Point Thomson litigation and securing necessary local, state and federal permits is imperative to maintain the pace of Point Thomson development."

The question naturally came up at the legislative hearing as to when a settlement could be finalized.

"When would you anticipate that the deal would be official and could be made public?" Paskvan asked Sullivan. "What's the timeline on that — is that 90 days, 45 days?"

Sullivan replied: "You know, Mr. Chairman, I really don't know. Our interest would be soon. In some ways those discussions right now are ... the timeline of those, we're not necessarily driving that anymore."

The other committee co-chairman, Republican Sen. Tom Wagoner of Kenai, said he's been involved with the issue of Point Thomson development through three administrations, and he congratulated Sullivan on getting this far.

"I know it's been a real battle that started with the Murkowski administration and went right on through," Wagoner said. "Well, it's very, very essential to the completion of the large pipeline."

"Sen. Wagoner, we're not, it's not over yet," Sullivan said. "As you know, anytime you work on settling litigation it's never easy. You never get fully everything you want."

What sort of development?

Sullivan noted that, while Point Thomson gas is considered important for a North Slope gas pipeline, the field also is rich in petroleum liquids, and production of those liquids could help stem the oil throughput decline on TAPS, the trans-Alaska pipeline system.

While construction of a gas line appears far from imminent, with no project yet confirmed, ExxonMobil itself created an incentive for wrapping up a Point Thomson deal as quickly as possible.

The company has pledged to begin production of 10,000 barrels a day of natural gas condensate, a liquid hydrocarbon, from Point Thomson by year-end 2014.

Already, the company has drilled two wells at Point Thomson, having obtained special permission from DNR in 2009 to sink the holes on two of the unit's 31 leases. ExxonMobil and its partners proceeded with the drilling as part of a strategy to hang onto the field, which is worth billions of dollars.

But the Nabors 27-E rig used to drill the wells has been demobilized, and ExxonMobil would appear to have a tight window now for installing facilities to produce the condensate by the 2014 deadline.

A 22-mile pipeline also must be built to connect the remote Point Thomson field to the Slope's existing pipeline network.

Of course, the deal now on the table between DNR and ExxonMobil might feature a whole new development scenario.

"The settlement is focused on the development of the Point Thomson unit which contains both hydrocarbon liquids and gas and we believe that the settlement of this litigation should help advance the strategic goals of filling TAPS and commercializing North Slope gas," Sullivan told legislators. ●

—Kristen Nelson contributed to this article

Contact Wesley Loy at wloy@petroleumnews.com