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HORIZON

Alaska Gas Pipeline: 40 Years on, Prognosis Still Uncertain

Since the late 1960s when Humble Oil, now Exxon Mobil, and Standard Oil of Ohio, now BP, discovered the largest single oil and gas field in the US at Prudhoe Bay on Alaska's North Slope, they have been trying to find an economically viable way to get the natural gas to market. Getting an oil pipeline to an export terminal at an ice-free port 800 miles away was a big enough challenge. It took the 1973-74 Arab oil embargo to galvanize political support and overcome environmental opposition. Oil finally began flowing in 1977.

Expectations were that a gas line to the US lower 48 would follow shortly, but more than 40 years have passed, with two high-profile proposals — the Alaska Northwest project and, recently, BP and ConocoPhillips' Denali venture — going to their graves. Alternative plans to ship the North Slope gas via in-state lines to Valdez, near the existing oil port, and convert it into LNG have not gained needed traction either.

> ***If shale were an impediment, why would Exxon be involved in an Arctic gas pipeline of any sort?***

So what are prospects for the remaining proposal on the table, TransCanada PipeLines and Exxon Mobil's pipeline project? The sponsors offered prospective shippers two configurations during last year's open season: a line connecting to Trans-Canada's Canadian transport infrastructure into the US, or a line to Valdez, where an LNG plant could be constructed by a third party. Results of the open season have not been disclosed. TransCanada Vice President Tony Palmer tells WGI that the project is on schedule to file for clearance with the Federal Energy Regulatory Commission in October 2012. Most, but not all, pipeline-customer issues have been resolved, he said, without indicating whether customers favor LNG or the line into the main North American grid.

Palmer did take issue with one reason Denali officials gave for pulling the plug on their project: the abundance of shale gas and resulting low gas prices. "Firstly, gas prices today are not what the project is focused on. It's really ... gas prices beyond 2021 and for the next 20-50 years that matter," Palmer said. "It is the view of our customers that matter, and what a pipeline company can try to do is get a commercial deal that will work for the parties."

Partner Exxon, the largest gas reserves holder in Alaska, isn't talking much (p5). However, Exxon is also one of — if not the — largest holder of unconventional gas resources in North America. If shale were an impediment, why would Exxon be involved in an Arctic gas pipeline of any sort, either in Alaska or in Canada's Northwest Territories, where its Imperial Oil affiliate leads the Mackenzie Gas Project (WGI Jan.12,p4)?

Bill Gwozd, vice president of gas services for Calgary-based consultancy Ziff Energy, shares what is apparently Exxon's view, that by 2020 and beyond, shale gas may not be an issue, given the rapid decline in conventional supplies in Western Canada and the Gulf of Mexico. Gwozd says that North America will eventually need not only Alaskan gas, but all the shale Canada and the US lower 48 can supply, as well as LNG imports to balance the market — not LNG exports.

North Slope operational considerations have to be factored into the equation, too. Prudhoe Bay long since became a gas field with associated liquids rather than an oil field with associated gas, as it was initially. The gas handling plant at Prudhoe Bay processes about 9 billion cubic feet per day (93 billion cubic meters per year) of raw gas. After NGLs, carbon dioxide and gas for local use are extracted, about 8 Bcf/d is re-injected into the field. The CO2 also goes for enhanced oil recovery.

Exxon has begun developing the adjacent Point Thomson gas-condensate field even though some lease issues with the state have yet to be resolved (WGI Dec.8,p8). For now, the gas will be cycled and the condensate recovered and mixed with North Slope crude to help keep TransAlaska Pipeline System supply above minimum operating levels. However, Point Thomson gas will eventually have to be produced.

Alaskan North Slope wells are already drilled, so that cost is sunk. The main cost of getting the gas to market is a transportation system — which won't be cheap. The TransCanada-Exxon project offered producers a choice between a 40 inch, 3 Bcf/d LNG option or a 52 inch, 4.5 Bcf/d link into

TransCanada's existing system at the British Columbia-Alberta border. Depending on the configuration, cost estimates vary from $20 billion to $41 billion.

Three LNG projects have been proposed for British Columbia, two near Kitimat and one for Prince Rupert. These would be too distant for Alaskan gas to be economical as feedgas, especially with trillions of cubic feet of unconventional gas available nearby, so they would be competing with Alaskan LNG for markets in Japan, South Korea and China. Royal Dutch Shell, operator of 2 Bcf/d BC LNG at Prince Rupert, has a partner in each nation — Mitsubishi, Korea Gas (Kogas) and PetroChina — plus other long-standing Asian customers. Apache, EOG and Encana are partners in the 700 million cubic foot per day Kitimat LNG, expandable to 1.4 Bcf/d. Douglas Channel LNG is a micro-project with a capacity of 125 MMcf/d (WGI Mar.23,p2).

By the time a final decision is taken on an Alaska pipeline, the Canadian LNG projects could be under construction and a clearer picture of intermediate and long-term Asian demand available. And Exxon's perspective is nothing if not long term.

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