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**ALASKA STATE LEGISLATURE**
House District 35

September 22, 2009

Commissioner Pat Galvin
Department of Revenue
PO Box 110400
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Commissioner Galvin,

The public conversation over natural gas has turned from AGIA Canada vs. Valdez LNG to an in-state line. In Harry Noah's second legislative briefing presentation the statement was made that four situations were to be analyzed: 250 mmbtu/day, 500 mmbtu/day, 750 mmbtu/day and 1b/day. Half of these appear to be predicated on failure of either AGIA scenario because they are beyond the 500 mmbtu/day threshold limit for state participation in AGIA. Although jobs and gas for Southcentral Alaska appear to be the prime considerations, I am concerned that the presumption throughout both AGIA and ACES that gas would be the future state revenue source as North Slope oil declines has been totally absent from the conversation.

The question continuously arises about fiscal certainty and a discounted percent profit tax for gas vs. oil. Although the Governor has specifically stated that now is not the right time for that conversation, I want to see some analysis as to the potential for avoiding that conundrum, specifically if North Slope gas was converted by Gas-to-Liquids (GTL) technology and then taxed as oil as are natural gas liquids.

The GTL discussion has generally focused on Ultra Low Sulfur Diesel. That process is generally recognized as using about 40% of the gas for the conversion process and creates the problem of transmission of a fully refined product concurrently with crude down TAPS. Dr. Chukwu from the University of Alaska Fairbanks and others have suggested that stopping the conversion to GTL at the initial synthetic crude oil stage (syncrude) would only consume about 20% of the gas and not incur the loss of value from mixing a fully refined and unrefined product.

As we continue discussions on a pipeline to carry ANS gas to market in gas, I would like to pose a few questions for your consideration and response. These deal with the basic economics of monetizing ANS gas as GTL syncrude and sending it down the existing TAPS pipeline and more specifically concerning the Alaska tax and royalty value:

1. Using the assumption that 20% of ANS gas will be needed for the conversion process from gas to syncrude, what is the estimated financial differential for the State between 80% of ANS gas monetized as syncrude and sent down TAPS and taxed as oil, and 100% of ANS gas sent down a gas-line and taxed as gas? This assumes the current tax rates are not modified.

2. As state royalty provisions allow gas used on lease to go untaxed, please analyze the impact of the loss of the 20% of royalty and tax on the gas used in the conversion process of ANS gas. Would the increased value of product as oil offset any such loss?

3. Is not receiving the 20% royalty and tax (for gas used on lease in the conversion process to GTL) a reasonable incentive to stimulate GTL production, which would give us more revenue if employed? Many think the legislature will remove the 20% incentive if anyone employs GTL on the lease. If it is determined to be of enough value to Alaska to promote GTL, should we take a proactive stance allowing this 20% as a lease expense?

4. What would be the value of the reduction in the TAPS tariff be to the State if we went from the projected throughput to projected throughput plus 375,000 to 450,000 barrels per day of commingled crude/syncrude for as long as it would take to utilize the ANS gas? [I am simply looking at taking existing estimates of TAPS throughput with annual production decline and assuming the same existing calculation for production and transmission utilized for the AGIA future estimates. According to Qatar major projects website Exxon/Mobile project would utilize 1.8bscfd of gas to yield 150,000b/d GTL and Shell project will use 1.6bscfd to yield 140,000b/d. That would extrapolate our 4.5bcfd to 375,000 barrels of GTL per day. However, that would be for fully processed Ultra Low Sulfur Diesel so actual volume may be over 400,000 barrels per day if the syncrude process saves about ½ the conversion gas. The only direct reference of syncrude conversion I have is from SPE Journal of Petroleum Technology 2/2009 Technology Update which gives 200barrels/day syncrude from 2mmscfd - which would equate our midpoint 4.5bcf to 450,000barrels per day. Maybe we could estimate the State's value with these as high and low cases?]

5. Previous estimates were that GTL production would extend the life of TAPS by 35 years. Do we have any estimate of what value that would be to the State? Or what costs and risks to the State would be avoided by TAPS utilization for a GTL option?

6. What does the price of gas have to be in relation to the price of oil (eg. 10:1 or 15:1) before it makes more value sense for the state to support sending gas down the existing TAPS line as oil, vs. sending it down a gas line as gas? Or does this calculation really have absolute price points more than value ratios? I assume there is a low break-even price with escalating value differential above that but I am only looking for rough estimates or the main factors for consideration, not exact numbers.

7. If Outer Continental Shelf (OCS) development leads to the exploitation of major gas fields in federal waters, and if this OCS gas is sent down a gas-line through Alaska, it would seen that currently the benefit to the State (other than economic synergy, on-shore support and jobs) would be a volume related reduction in the gas-line tariff. If OCS gas were converted to syncrude at a processing plant on the North Slope and sent down TAPS, would the oil tariff decrease be of similar value?

8. Could Alaska tax OCS gas as oil if it was 'produced" as oil within the State? If not currently, could state legislation enable this recovery of value instead of just producing gas volume transmission tariff reduction? Although ACES makes the tax company specific, but here we have no qualifying lease expenses as it is located in federal waters, can we make a very general base case tax estimate for an 'average' major producer per bcf piped ashore to a GTL syncrude plant?

Thank you for your consideration of these points, and your detailed and thorough response. I understand that we will be meeting in October to discuss these points. Feel free to call or e-mail for clarification or questions on any of the above issues.

Sincerely,

Paul Seaton

Representative Paul Seaton