Stranded Gas Hearings
(0409020900 Minutes)

Natural Gas Liquids, In-State Natural Gas Processing, and Petrochemical Facilities
Lesa Adair, Vice President, Muse Stancil, September 2, 2004.

MS. LESA ADAIR, Vice President of Muse Stancil, told members she would review natural gas liquids, the market in general, and the options for in-state processing and petrochemical facilities, as well as the alternatives. She referred members to page 2 of her handout and said she would talk briefly about the natural gas liquids (NGL) market and focus on the United States and Canada, relative to potential NGL production from Alaska. She began:

> If we look at 2003 total year numbers, the production of natural gas liquids in the Lower 48 totaled about 1.7 million barrels. That production was primarily concentrated in the southcentral United States - no big surprise there - that's where the bulk of the oil, and particularly gas production, is in the Lower 48 with about 66 percent of the production coming from that particular area. In addition, we imported about 165,000 barrels per day of NGL production, primarily from Canada, coming through pipelines into the upper Midwest.
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> In contrast, let's talk a little bit about Canadian production. Their production was about 670,000 barrels a day and, of course, their exports just happen to equal our imports at about 165,000 barrels a day. Based on numbers we've been provided from the Department of Natural Resources and looking at the total potential production and throughput on NGP and the compositions that are expected of NGLs in the gas, it looks like the potential production from the Alaska gas pipeline (AGP) throughput for NGLs would be on the order of 160,000 barrels a day but about 120,000 barrels a day of that would be ethane. Contrast that with U.S. supply of about 625,000 barrels a day of 1.7 million barrels being total ethane, the AGP liquids are going to run about 50 to 60 percent ethane, as opposed to current Lower 48 consumption and production, which is about one-third ethane. Canada is very much the same. They've got a slightly higher percentage of ethane at about 40 percent. So AGP is going to be more highly leveraged on ethane.
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> Let's look at how the market really works in terms of natural gas liquids today. In the Lower 48 we have two, really, principle market hubs - Mont Bellevue, which is located on the Texas gulf coast and Conway, right in the center of the United States near Hutchison, Kansas. Both of those locations are interconnected with large diameter transmission piping. Further, they are interconnected all the way back up into Edmonton, Alberta through a series of pipelines so that the entire Lower 48 and Canadian natural gas liquid markets are very well integrated.
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> As a result, what we tend to see, because the largest consumption of natural gas liquids occurs here in Pad 3, and it's specifically on the U.S. Gulf Coast, is that the prices are pretty much set by the consumption that occurs in Mont Bellevue and then the whole rest of the market adjusts, all the way back up to Edmonton, off basis differentials for transportation. From time to time, there can be regional disruptions in supply, seasonal supply and demand that may throw those particular relationships out of whack for a little while but, in general, the price is pretty much netback from a market clearing price at Mont Bellevue.
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> The other key thing to keep in mind about these market centers and again, the biggest ones in the Lower 48 are Mont Bellevue and Conway, Sarnia is also north of Detroit - is also a large NGL market center, and then Edmonton, Alberta. These particular areas have large fractionation units, multiple large fractionation units. And the other distinctive factor there is that they have both the demand for the NGLs in those areas and significant underground storage in the form of salt cavern storage. Salt cavern storage is the most efficient way to store natural gas liquids. In Conway, they really only have the fractionation in the underground storage. They're really a distribution point balancing the demand between the northern and southern parts of the United States and Canada, whereas in the other markets, they're all derivative, manufacturing

polyethylene, polypropylene and so forth in those areas.

If we look at product price trends, and truthfully all we want to talk about here are the trends, the ethane natural gas liquid tracks the natural gas price very closely. It is correlated very well to the natural gas, while propane and butane track the crude oil price. The important thing to understand with gas processing, as opposed to refining, for example, where all of the products that are derived from crude oil generally follow the crude oil price, there are so many derivative markets for natural gas liquids that we don't have the gas price setting the price for all the products. They move independently. As a result, the margins move independently and you can have a lot more volatility in the margins.

Let me just point out a couple of spots here to make that clear. If we look here in the period of 1995, you can see that crude oil prices are tracking fairly flat in this area but you can see natural gas and ethane moving independently in a downward trend in this particular area. Propane and butane prices were likely relatively stable while gas prices were falling. The other thing to notice is that as these prices move, you don't necessarily get the same order of magnitude shifts, even though they may be following the same trend. For example, in the period towards the end of the curve out here in the 2001 forward period, crude changed about $10 a barrel or moved about 40 percent of its value, where gas moved $3.50 for about 140 percent of its underlying value so large change is not necessarily the same order of magnitude.

When we look at natural gas processing, we have to look at what is the value of extracting these natural gas liquids from the gas itself and that's really what the next page 5 is focusing on. Here, as opposed to the prior slide, what we're looking at is the dollars per MMBTU for both natural gas, the blue line - the bottom line in most of the chart, and ethane, which is the red line, the top line. And we're actually able to compare the value of the ethane if it's sold on the top line in red as a liquid directly to the value of the ethane if it's sold as natural gas.

The important thing to recognize here is if you look at the period of the early 1990s, you can see a fairly wide difference between those two lines indicating that if you take ethane out of natural gas, you don't sell it for the blue price - turn it into a liquid, sell it for the red price, you make the difference. As you track across time, move closer to current and, specifically after late 2000 where you see the great big lovely peak in prices, you can see those lines moving much closer together. As those lines move closer together, the value of ethane as a liquid is becoming almost equal to the value of ethane as a natural gas. What that says is there's no incentive for a processor to change it from gas to liquid. Rather, he's indifferent. He'd rather just sell it as natural gas and not have to pay the processing cost.

NGL pricing on page 6 - there's a lot of debate about what's going to happen to pricing and, frankly, one of the things that I think is going to create some disruption in the market may be the timing and the actual location of the extraction of liquids from AGP. EIA has rolled, I believe, Alaska natural gas into their forecasts. At least it appears to be in there for everything I've looked at and they're forecasting that on average, on an annual basis, they think NGL prices are going to remain essentially flat on a real basis in the long term. They're projecting the increase of something around 1 percent, slightly more than natural gas, which leads me to believe that their view is that we may see a slight improvement in gas processing margins over time. But specifically for AGP liquids, what we have to be concerned about is where those liquids are going to end up and specifically, how much it costs to get it there because obviously we're not going to have enough demand in Alaska for all of the natural gas liquids that can be extracted, therefore you're going to have to deal with export pricing and that really is going to be the biggest determinator really of what those prices are netted back to the wellhead or to the border, whatever basis you want to look at.

The other thing that you need to think about too is that because AGP liquids will be highly leveraged to ethane, we have to think about where will all of the ethane go but the best place for all the ethane may not necessarily be the best place for the propane and the butane. Because these products all go to different derivative markets, you may have widely differing economics, depending on the ultimate destination of each segment of the NGL production.

Let's talk a little bit about historic processing margins. We'll look at the Lower 48 and maybe that will help us get some idea of what you'll be faced with in looking at AGP liquids. My firm, Muse Stancil and Company, publishes every month an oil and gas journal - these NGL extraction margins. And really what they're meant to represent are hypothetical plants in the mid-continent and the U.S. Gulf Coast. And really, this margin is meant to represent economically how is gas processing doing. In each individual situation the margins may be higher or lower but, on average, this tells us how margins are changing over time. In the mid-continent we tend to see fairly rich natural gas streams. Those plants do require usually a little bit more compression. On the Gulf Coast you have less compression but much leaner gas, much larger plants. And you can see that if we look at the trend, over time, from early 1990, that we are in a significant long, very slow decline in natural gas processing margins. This particular calculation is done from the standpoint of the plant operator, assuming that he buys the gas, he extracts the liquids, and pays all of his operating costs. So this gives us the cash margin really, that he would earn for performing those services. It does not take into account the overhead, which can vary widely from company to company or the capital expenditures that may be going on - the return of or the return on capital. So this is sort of a before tax type number. But you can definitely see we're in a downward trend long term and, for gas processors in particular, the last three and one-half years have been pretty tough. On the U.S. Gulf Coast you can see that since 2001, margins have actually averaged negative cash return.

Now what is the producers' perspective on this same profitability for gas processing? One of the things that's pretty typical in gas processing contracts that we see all over the world, not just in the Lower 48, is what a processor agrees to produce or to process gas for a percent of the proceeds. In other words, he captures the percent of the product and that's what he takes as his payment for the services. So the producer is used to paying a percent of his proceeds over to the processor and so one other thing that we look at is from a producer's perspective, he usually pays for all the fuel. He has to bear the shrinkage - that is how much his gas volume decreases when he extracts liquids, and also the transportation and fractionation charges from moving those products away from the plant. So we look at it from his perspective and we say okay, if you're going to process your gas, how much of a liquid do you need to get back to pay for processing, to pay for fuel, for the shrinkage, and the transportation fractionation? And if you look back in the early '90s, you can see that a producer in the mid-continent or on the Gulf Coast was making money if he got 60 percent of his proceeds back.

But over time, just as we saw with the gas processing margin, that amount of liquids he needs to receive to pay for processing has continued to increase. When the value of the liquids exceeds the 100 percent bar that means that the producer has gone from earning some income for processing to paying for it; in other words, it's become a cost center. He can't ever get enough liquid back to pay for the cost of processing.

And so, in the period since late 2000, we have begun to see a shift in the mentality in the industry that more and more people view processing, at least in the short to medium term, as a cost center rather than a profit center. There are unique opportunities out there, depending on composition, capital expenditures and so forth, where some people are making money but, again, as a barometer in general, processing has become more of a cost than a profit center.

Now I'd like to shift gears a little bit, moving on to page 9, to talk about alternative dispositions for the AGP-NGL throughput. The Department of Revenue has obtained us to assist in developing their understanding of the economics of these different alternatives and so one of the first things we took a look at is what particular areas, what market centers, make the most sense. If we look at extraction in petrochemical manufacturing outside of the State of Alaska, the first place that you think of is the U.S. Gulf Coast, where over 80 percent of the capacity for [indisc.] production in North America is located. Other centers include in Alberta, primarily in the Edmonton area, where about 12 percent of the capacity exists, and then Sarnia and other various locations in the U.S. Midwest, which tend to be large isolated manufacturing facilities. The nearest infrastructure of any plausible size, and this includes derivative manufacturing of ethane, the fractionation capabilities and the underground storage we talked about earlier, is really Alberta. If we look though, at Alberta's ethane balance, they're currently manufacturing just a little bit more, not even 10 percent more ethane than they utilize, and so they're pretty balanced on supply. We do know that their availability of liquids is going to go down over time as their gas continues to decline and so, over the medium to long term, there may be some opportunities to supplement the ethane that they're using in their petrochemical manufacturing there in Alberta. Their total demand currently is about 250,000 barrels a day. If we look at AGP's potential of 120,000 barrels a day of ethane, that's roughly half their current capacity, so that's an awful lot of NGL or ethane in particular to have to displace into Alberta. However, there could be additional capacity installed there or additional take-away pipeline capacity installed to handle the incremental ethane coming off of AGP.

Extraction in Alaska - first of all we'd have to think about the fact that when we pull out the ethane, other things are going to come with the ethane. It's not likely that we could come up with an economic solution, which says we build a natural gas liquids pipeline to take the excess propane, butane and so forth that comes out with the ethane to a market, as well as a gas pipeline. So our feasibility look really centered on the notion that you would extract what you need for manufacturing in Alaska and that everything else would go back in the AGP so that you would only have to build one piece of transportation infrastructure for the state.

To have a market for that primarily ethane would also require the development of a petrochemical manufacturing complex and, most likely, that would be ethylene going to polyethylene and then the infrastructure to support that, including the storage utilities, electrical and so forth. It's possible that you may require some additional transportation infrastructure but our design is not at a level yet to really determine that. Polyethylene is pretty easy to transport - you can put it in rail cars, hopper cars, in bags and transport it by rail and marine.

The facility would look something like this on page 10. The facility would handle about 1.4 bcf of throughput on the extraction plant. That's out of a roughly 4.3 bcf total throughput on AGP. From that we would produce about 40,000 barrels per day of ethane to be fed to the ethylene facility and another 1,000 barrels a day of propane or so for local consumption. Any incremental propane that couldn't be sold and butane that's extracted would go back into the pipeline for transportation to the ultimate pipeline termination point. You would also be able to produce commercial quality natural gas for local distribution off the top of the extraction plant. And any residue gas that you couldn't sell, which our figures show would be about a B [BCF] or a little over a B [BCF], would go back into AGP as well.

The design and construction of this sort of facility is probably duplicative in that you would ultimately size all the facilities at the terminus of the main line pipeline to handle 100 percent of the throughput because, obviously, if you're going to have one ethylene plant, one polyethylene plant, they're going to have to be in shut down and turn around for some extended periods of time and you wouldn't want to have to shut down your pipeline to do that so you would probably just have a slightly bigger extraction plant at the terminus of the pipeline to allow you the flexibility to mute that gas in either direction.

Downstream of the extraction plant, on page 11, your ethane would feed an ethylene cracker. You would produce ethylene, which would feed a polyethylene plant and then produce the polyethylene resin, which would be little pellets that look like little chips of wax. There are some by-products from the production of ethylene, however ethylene production is by far the most efficient process. If you try to use propane to propylene or naphthenic-type cracking, you get a lot more by-product, stuff you can't use. If you're in Edmonton or on the U.S. Gulf Coast, those by-products can be sold into other related petrochemical facilities in the area - refineries, other petrochemical manufacturing. Here we've assumed that all these by-products have to be burned as fuel because we are not anticipating that we would have additional available infrastructure to absorb those by-products.

In summary, if we look at Fairbanks versus other potential points for extraction and downstream processing of NGLs, we believe there will be an attractively priced feedstock at Fairbanks that, because you're exporting the gas, the price of gas at Fairbanks is likely going to be some Canadian border or Alberta-related price netted back from the tariff, which should lead you to a fairly inexpensive price for feedstock in Fairbanks. Fairbanks also does, with the rail connection, offer a link to waterborne transportation and there is demand for polyethylene resin in California. Now that demand is being met today so you would have to be able to penetrate the market at the right price to make sure you could get all the placement of that market.

There are synergistic benefits, including pipeline quality natural gas availability to Fairbanks and possibly other areas. You would have to have electrical generation within the complex and you could possibly oversize that facility and provide additional merchant electrical power delivery into the grid.

The disadvantages we see of the Fairbanks location is that there is some variability in the gas composition over time, that's just a function of how gas comes out of the reservoir and that's something we deal with everywhere. However, here it's going to be very localized. In the Lower 48, it's kind of spread out all over the place. What that means is you have to size your gas processing facility to be able to ensure that you're always going to be able to extract enough ethane to keep your ethylene plant going, which means it's probably a little bit bigger than it would generally need to be.

There's going to be a little bit of inefficiency in processing because you're going to process 1.5 bcf of gas in Fairbanks; 1 bcf of that is going to go back into the pipeline. When it does, it gets remixed with other components and has to be reprocessed again at the terminus of the pipeline so you do have to have the capacity and pay the operating costs for that to be processed twice. We talked about the non-optimal sizing. You're going to want to make your downstream facilities big enough to take all the gas in the event that you've got an outage in your ethylene production or just for routine maintenance of your ethylene facility.

In looking at capital costs - and I think this is one that's real important, especially since we've just in the last several weeks learned that there are at least three ethylene plants in the Gulf Coast that are going to be shutting down because they're at a cost disadvantage. Fairbanks appears to be about a 35 percent higher capital cost than installing similar facilities on the U.S. Gulf Coast, and perhaps 25 percent higher than an Alberta type installation. That is before we consider the fact that we're going to have to add infrastructure that already exists in Alberta or exists on the U.S. Gulf Coast that we could incorporate and use so there would be additional costs above and beyond that. The fixed operating costs are likely higher, due to wages and also due to the fact that you're going to have to fly in expertise, parts, and equipment, which are readily available in those other centers. We talked about the lack of supporting infrastructure and the fact that the by-products really don't have a market here so anything that we create out of ethylene manufacturing that's not pure ethylene is going to have to be burned probably as fuel in the facility.

If we look at the preliminary economics, and this is a very high level analysis, but it appears to us that the production of the ethane in Fairbanks is just economically less attractive than in either Alberta or on the U.S. Gulf Coast. You've got the advantage of potentially a lower feedstock price than your ethane. The lower variable costs, and by that we mean fuel, if your gas is cheaper, it's cheaper to burn as fuel as well. But that's more than offset by higher fixed operating costs, the location differential in a remote location, and the lower product value due to downgrading those by-products to fuel.

The significantly higher capital cost is probably also going to be a disincentive for most of your major manufacturers to invest. If they're looking at a location in Alaska where there's stranded gas versus a location in Asia where there's stranded gas and they can build a plant for 30 to 40 percent less than Alaska, they're more than likely going to go to Asia. We see an awful lot of manufacturing of facilities being installed in Asia today and, in fact, the U.S. Gulf Coast facilities are running at less than capacity because they're having trouble competing with the more efficient and cheaper product out of the Asia Pacific.

Looking at recent historical U.S. Gulf Coast margins for ethylene production, we're assuming - we believe Fairbanks could probably achieve a similar margin because its got the feedstock advantage but it's going to have higher investment costs. But, if it's able to do that, it will have a significantly less attractive rate of return simply because you've got a higher capital investment. Alberta's rate of return is probably a little bit higher. Their contracts are structured a little bit differently than the U.S. Gulf Coast. So, Fairbanks is pretty economically disadvantaged in terms of trying to compete in the world market. And that's all I have. I'm happy to take any questions.

CHAIR SAMUELS asked, regarding the capacity, if Ms. Adair said the capacity from Fairbanks south would have to be the same as the capacity from the North Slope to Fairbanks, just in case the plant was out and had to be modified.

MS. ADAIR said that is correct and, more than likely, to keep the gas flowing, the downstream facility would be sized as if Fairbanks wasn't there. That would provide the ability to keep the gas flowing if Fairbanks had to be shut down. The incremental cost in terms of the pipe size is not that great.

CHAIR SAMUELS asked what percent would be taken out if the plant was up and operating as intended as it goes by Fairbanks; and how much empty space would be headed for Chicago.

MS. ADAIR replied, "About 1/2 B [BCF] is what our numbers show because we pull off 1.5 and we put back in about 1, so about 500,000."

SENATOR RALPH SEEKINS asked how the NGL content of the gas envelope that comes off the North Slope compares to other areas or regions.

MS. ADAIR said the composition is more like a Gulf of Mexico type gas. It tends to have less propane and butane in it but has more ethane. From the extraction profitability standpoint, the propane and butane tend to be the higher value components of the gas. She noted as compared to the Lower 48 and Canadian production, Alaska gas is 50 to 60 percent ethane; the Lower 48 and Canadian gas is 30 to 35 percent.

SENATOR SEEKINS said the primary object is to get gas from the North Slope to someone who will burn it at a power plant or at a commercial application down the road. He asked, "Let's say we had a complete gas envelope that didn't have anything taken off from it and it got to the Canadian border. Is then that - what do we deliver out the other end? Is there any BTU per BTU relationship that exists when it comes back into the United States?"

MS. ADAIR replied the real question has to do with the way the major transmission line systems and local distribution systems are designed and, to a certain degree, how water heaters and stoves are designed to work with natural gas. She explained what you typically see in the United States are natural gas pipelines operating at 1,000 btu gas. Some operate as high as 1,050. In Alberta, the gas processing facilities that are remotely located do what is called dew point control. They strip out the heaviest liquids - propanes and butanes; and make it easier to move the gas in pipelines without a lot of liquids falling out. The problem with liquids falling out is twofold: a loss of efficiency and safety considerations. In the Alberta system, the heavier liquids are extracted in the field and then large straddle plants sit over their big gas transmission systems and extract the rest of the ethane. However, in all cases when looking at local distribution systems, the btus are very low so the producer does not have a choice. At some point along the value chain, the gas must be processed. The btu content must be reduced for distribution purposes and someone must pay for it.

SENATOR SEEKINS said everyone wants to make natural gas usable in Alaska in Fairbanks and with a line to Anchorage. He asked if the product that comes down that line to Fairbanks would be usable downstream in Alaska without any processing.

MS. ADAIR said it would not without some sort of processing, however, a petrochemical complex taking the product all of the way to polyethylene resin would not be necessary to make a commercial quality natural gas for local use.

SENATOR SEEKINS commented, "I've heard people talking about - well there are, on the other side of the border, there are people that are saying and they get to the Whitehorse area and they're saying if we can get that intact envelope here, we can strip that stuff off, we can get it down to the Alaska coastline and get it out to the markets if Alaska doesn't. Is that a possibility? Is there any discussion about that that you're aware of?"

MS. ADAIR said she is not aware of any such discussions and has not been asked to study that question. She noted the potential limitation revolves around having enough heavy-duty vessels to move that high-pressure product, particularly ethane.

SENATOR SEEKINS said many [legislators] want to have in-state processing to enhance Alaskans' overall quality of life. He asked Ms. Adair, with that in mind, if her basic conclusion is that may not be economically feasible.

MS. ADAIR said the problem is that Alaska will have a hard time competing in the worldwide market if it has integrated petrochemical manufacturing in-state.

CHAIR SAMUELS asked what type of processing facility would be required to pull the heavy liquids out to service Fairbanks and Anchorage.

MS. ADAIR explained the processing would require the same technology to produce the natural gas liquids but the processing plant would be a different size and the cost would be much smaller. It would not require any of the downstream processing and the liquids that were not used could be put back into the pipeline.

SENATOR SEEKINS asked if those liquids would be put back in the gas pipeline as opposed to the oil pipeline.

MS. ADAIR said that is correct and that it would be a relatively small amount compared to the overall throughput on the AGP.

CHAIR SAMUELS referred to page 8 and asked if demand for the liquids drops, the processing cost goes up for everyone, and whether the demand has dropped so low that the manufacturers cannot recover their operating costs.

MS. ADAIR said the margin for gas processing is very volatile and feedstocks, which are natural gas, work off a different supply and demand curve than the products do. What has happened is that the demand for natural gas in and of itself is so strong that, to the extent everything possible is left in the gas, it is more economically beneficial to do so. She continued, "And that's really what creates this situation is gas prices are so, so high. People would like to - producers would like to sell their propane as natural gas if they could in some places but, because of the safety considerations, they are not able to do that. So, demand is still very strong for all of these products."

SENATOR SEEKINS asked, " It appears to me then what we're saying when we look at this chart on page 8, that this is kind of a stand-alone - I'm buying the gas, what the price of the gas is. It's a separate accounting for that structure but what you're saying is it's necessary for them to take some of these liquids out?"

MS. ADAIR said it is.

SENATOR SEEKINS asked if the break-even chart is based on having to buy the liquids but not considering that they have to be stripped out.

MS. ADAIR explained that it is based on the producers' opportunity costs - the gas given by the producers to create the liquids. She continued, "Some of that he gives up because he has to shrink out the propane and the butane. Some of it he gives up because it's burned as fuel. That's gas that he could be selling for revenue. So it's that whole opportunity cost that he bears to produce those liquids. That's really what the chart is driving at; it's that his cost has gone up."

SENATOR SEEKINS said often the expense structure is a necessity, not necessarily a reduction in opportunity.

MS. ADAIR said the producer may have flexibility to a certain degree, depending on whether he or someone else is processing for him, to reduce the amount of processing done. Generally producers sell to someone else who does the processing but some producers in the Gulf Coast retain the right to not process their gas when prices get high.