Comments provided by Larry Persily, Federal Pipeline Coordinator

At the Request of House Resources Co-Chair Eric Feige – March 31, 2014

"I looked over the thoughtful and detailed questions that Rogers Marks submitted to the committee and offer my observations/comments to some below (those with federal issues or where I have knowledge from my work as Federal Coordinator or my past role as deputy commissioner at Revenue)"

FOR THE PRODUCERS

1. How would you feel about a provision in the legislation that in exchange for taking the taxes and royalties as in-kind gas, the producers would agree to purchase and dispose of the state's gas at the same price that the producers receive for the rest of their gas, just as is done with in-value now? The problem is that not all LNG is sold at the same price or on the same terms — each contract is different. Pricing can be different, not just the percentage linkage to oil prices but caps at the low end and high end and "softening" of the linkage curve at high oil prices; the number of years; volume flexibility and destination flexibility; peak deliverability (such as extra gas in the winter); shipping (does the seller or buyer arrange for shipping); and on and on. It's just not the same as for oil, where there is pretty much a daily price for all oil cargoes or a certain quality.) It would be difficult for the state to demand — or want — the same contract terms as the producers with every LNG buyer in every transaction. I'd expect the gas from Alaska LNG could be sold off to a dozen or more different buyers, all with different contracts. Besides, the state may very well want different contract terms with LNG buyers than the producers. Maybe there would be a choice between a higher price with a buyer's option to reduce volume in certain circumstances vs. a lower price and a 100% lock on 100% of the volume with no flexibility. Which should the state select? Protection against below-market contracts is a good idea, and I would expect the state could write into its marketing services RFP a provision ensuring disclosure of other contracts for sake of comparison.

2. Are there any precedents under FERC Section 3 regulation where there are large pipelines with local consumption of transported gas? The only pipelines covered by FERC under Sec. 3 of the Natural Gas Act would be pipelines that exclusively serve an LNG plant, as opposed to a Sec. 7 interstate line that also happens to feed an LNG plant. As such, when you think about Lower 48 LNG plants, the pipelines to the plants either already existed in the area (think U.S. Gulf Coast) and therefore were Sec. 7 rate-regulated lines serving interstate and intrastate customers, or they are short new spurs to the LNG plant. Those short spurs, however, also are most likely part of the interstate pipeline network, carrying interstate gas to the plant. Which is a long way of saying I doubt whether there are any large Sec. 3 pipelines that carry gas **only** to and from an LNG plant and limited local (in-state) buyers/sellers, thereby escaping Sec. 7 FERC rate regulation. I believe there could be some very short spurs that serve only an LNG plant and no one else, which would be covered by Sec. 3, which would mean a FERC-led environmental impact statement and authorization for construction and operation, but not Sec. 7 interstate rate regulation. The Alaska LNG project is different from anything else in the Lower 48.

FOR THE ADMINISTRATION

1. How would you feel about a provision in the legislation that in exchange for taking the taxes and royalties as in-kind gas, the producers would agree to purchase and dispose of the state's gas at the same price that the producers receive for the rest of their gas, just as is done with in-value now? Same answer as above.

FOR AGDC

3. What is the possibility of 100% state debt financing through revenue bonds and general obligation bonds? 1) I doubt the state has the debt capacity for that much in general obligation bonds, though I admit the rate would be less than a commercial loan if the state could actually float that massive of a bond issue; 2) And even if you could get 100% general obligation debt, any shortcoming in covering the debt in any given year from project revenues would require a politically painful direct draw on the general fund that year; 3) I am not aware of an LNG import or export project anywhere in the world financed with 100% project revenue debt (lenders have always wanted a hefty down payment on LNG projects), and I see no reason why Alaska LNG would be any different (actually, lenders might want a heftier down payment because of the perceived political risk in Alaska oil and gas politics); 4) Some lenders through the years have pitched the tantalizing prospect of 100% project revenue debt financing to the state, but I believe they have done so to entice business through their door (no offense meant to their marketing efforts).

4. What is the possibility of getting tax-exempt debt through the Alaska Railroad? I wonder how lenders would react to a scheme to use the railroad (with its own financial challenges) as a front to get tax-exempt financing to beat the IRS, when the railroad has not a dime of its own in the venture. Besides, when this idea was floated last decade, the railroad wanted a fee to serve as the front, something in the neighborhood of 0.75% — nothing is free. This entire discussion goes back a decade, when state officials realized the federal law that transferred the railroad to the state included a provision allowing the railroad to issue tax-exempt debt — but the law offers no specifics or guidance. Many state officials thought it would be a tough sell to get the IRS to go along with a multibillion-dollar tax-exempt bond sale for what is essentially a business venture (as opposed to a public-purpose development, such as a passenger train terminal). Senate Finance Co-Chair John Torgerson went out and paid for a legal opinion on the railroad debt issue (about 12 years ago). Perhaps he still has a copy? Note: People point to the tax-exempt bonds issued by the City of Valdez for the Alyeska oil terminal in the 1970s. True, that worked, but the law was later changed and you cannot do that again. (I also see that the railroad has gone out with an RFP to contract for a financial adviser to look at just such a venture. See http://alaskarailroad.com/LinkClick.aspx?fileticket=j_g9BuNzdSY%3D&tabid=408)

FOR TRANSCANADA

2. Are there instance in the pipeline business where pipeline companies absorb some pre-development costs if the project is not sanctioned? Yes, happens all the time.

FOR INVESTORS/BANKS

1. Would commercial or investment banks, private equity firms, or venture capital terms be interested in investing with the state as a partner? What rate of return would be necessary? No one will give you a firm interest rate quote until they see the total project; that's what FEED is to accomplish. It all depends on the project, the developer's balance sheet and the sales contracts. For example, Cheniere Energy needed cash for construction of its Sabine Pass, La., LNG export terminal. It raised much of its equity share by agreeing to pay 17% to a private-equity firm to help raise the 30% equity (down payment) required to borrow the other 70% of the money for construction.

2. What is the possibility of 100% state debt financing through revenue bonds and general obligation bonds? See above.

3. What is the possibility of getting tax-exempt debt through the Alaska Railroad? See above.

FOR FERC

1. Would FERC be comfortable regulating this project under Section 3 of the Natural Gas Act? FERC will not say anything until it has an actual application on its desk. But whether it is "comfortable" is not the issue; LNG plants are regulated by Sec. 3 – of the Natural Gas Act, there is no option. FERC has worked with Sec. 3 for years, and is familiar and comfortable with its job. Pipelines that serve an LNG plant can fall under Sec. 3; it's up to FERC. And since there is no interstate component to the Alaska LNG pipeline project as currently proposed, I believe FERC would lump the pipeline and the LNG plant into one environmental impact statement for health and safety and environmental concerns, which is the focus of Sec. 3. I also expect a project developer would want a single federal EIS by a single federal agency, rather than separate impact statements and separate timetables for the pipeline and LNG plant. As to pipeline tariffs, without an interstate component to the pipeline, there is no jurisdictional hook and no Sec. 7 tariff regulation by FERC. It's not a matter whether FERC is "comfortable" with that — it's the law.

FOR THE ENERGY DEPARTMENT

1. Would DOE revoke the LNG export permit if the gas were needed for in-state consumption? Please describe how that process would work. There is no formal process because it's never ever happened in the United States. Remember, until a couple of years ago, no one had ever tried to build an LNG export plant in the Lower 48 -- the only one was in Nikiski. Federal law allows the Department of Energy to suspend or revoke an export license, no question about the authority. In response to a question from Sen. Murkowski, the department in October 2013 wrote: "The Department takes very seriously the investment-backed expectations of private parties subject to its regulatory jurisdiction. As we have stated consistently, DOE would not rescind a previously-granted (export) authorization except in the event of extraordinary circumstances. ..." Besides, even if in-state need for North Slope gas increased, it likely would be such a small percentage (single digit) of the overall project that I believe one (or more) of the pipeline partners likely could fit that additional gas into the line for local off-takes. The better question would be to the Alaska LNG partners: How much additional gas could you fit into the pipeline for in-state off-takes by adding compression before you would need to add actual pipe?